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UNIVERSITY OF ALBERTA

EFFECT OF TEMPERATURE ON THREE-PHASE
RELATIVE PERMEABILITY

BY

MUHAMMAD ABDUL MUQEEM



A THESIS SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH
IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE DEGREE
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IN
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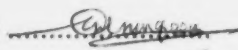
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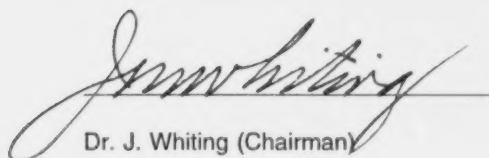
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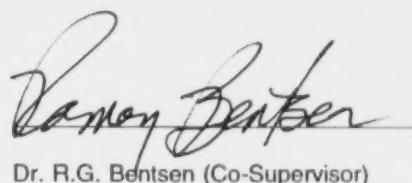
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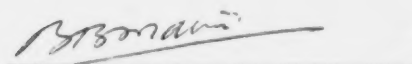
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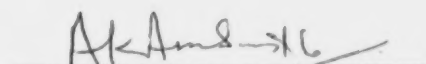
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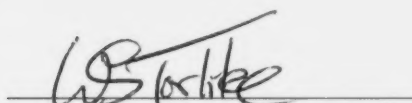
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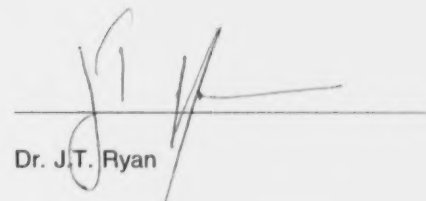
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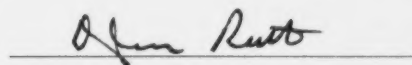
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To my parents

whose years of support, guidance and blessings made this work a reality

my wife, Titas

without whose love and sacrifice this work could not have been possible

my daughter, Tanziyah

whose curiosity kept me going on this project

ABSTRACT

Petroleum production often involves the simultaneous flow of three immiscible fluids through subterranean porous rock formations. Thermal methods for heavy oil recovery have gained wide acceptance in the petroleum industry. Three-phase relative permeability plays a central role in the analysis of the steam drive process for heavy oil recovery. Some experimental data are available for three-phase relative permeability at elevated temperatures. Unfortunately, no systematic study of the effect of temperature on three-phase relative permeabilities has been reported. This study was initiated to address these deficiencies and is believed to be the first extensive study undertaken to determine how viscous oil-brine- N_2 gas relative permeability changes with temperature.

An apparatus was developed and subsequently modified for the measurement of three-phase steady-state heavy oil-brine-gas relative permeabilities under high pressure, high temperature nitrogen flooding conditions. Experiments were conducted over a temperature range to evaluate the effect of temperature on three-phase relative permeabilities. The experiments were conducted under steady-state conditions so that instability phenomena were eliminated. Consistent, monotonically changing saturation trajectories were followed to minimize hysteresis effects.

Results indicate that, under these flow conditions, no significant temperature effects on three-phase relative permeability were found for a heavy oil-brine- N_2 gas system in clean unconsolidated Ottawa sand packs. The relative permeability of brine is seen to depend on its own saturation, while the gas and heavy oil relative permeabilities depend on the saturations of all fluids. Predictions obtained using models of Stone and Pope were used for comparison with the experimental data. The comparison was good.

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NOMENCLATURE

A	cross sectional area, m^2
A_{ow}, A_w	saturation exponent for oil/brine experiments (Equations 5.1 and 5.2)
A_{og}, A_g	saturation exponent for oil/gas experiments (Equations 5.3 and 5.4)
B_{ow}, B_w	parameters for oil/brine experiments (Equations 5.1 and 5.2)
B_{og}, B_g	parameters for oil/gas experiments (Equations 5.3 and 5.4)
a	parameter (Equation 2.8)
F	statistical F-distribution
g	acceleration due to gravity, m/s^2
k	absolute permeability, Darcy
k_j	effective permeability to fluid j , Darcy
k_{ocw}	permeability to oil at connate water saturation, Darcy
k_r	relative permeability
k_{rg}	relative permeability to gas in three-phase flow
k_{ro}	relative permeability to oil in three-phase flow
k_{rw}	relative permeability to brine in three-phase flow
k_{rog}	relative permeability to oil in oil/gas two-phase flow
k_{rgo}	relative permeability to gas in oil/gas two-phase flow
k_{row}	relative permeability to oil in brine/oil two-phase flow
k_{rwo}	relative permeability to brine in brine/oil two-phase flow
k_{row}^*	relative permeability to oil at irreducible brine saturation
k_{rwo}^*	relative permeability to brine at residual oil saturation
k_{rog}^*	relative permeability to oil at zero gas saturation
k_{rgo}^*	relative permeability to gas at residual oil saturation
L	length, m

m	mobility ratio
N_{cam}	modified capillary number (Equation 6.2)
p	pressure, kPa
q	volumetric flow rate, m^3/s
q_j	volumetric flow rate of fluid j , m^3/s
r^2	correlation coefficient
S	saturation
S_{Lr}	total residual liquid saturation to gas
S_{oi}	initial oil saturation
S_{om}	minimum value of the residual oil saturation
S_{or}	residual oil saturation
S_{org}	residual oil saturation to flowing gas phase
S_{orw}	residual oil saturation to flowing brine phase
S_{wi}	irreducible brine saturation
T	temperature, $^{\circ}C$
v	fluid velocity, m/s
z	height, m

Greek Letters

$\alpha, \beta, \gamma, \delta$	parameters in Equation 2.8
β_o	factor to allow for oil blockage by gas
β_w	factor to allow for oil blockage by water
∂	difference
μ	viscosity, $mPa \cdot s$
ρ	density, kg/m^3
σ	interfacial tension, mN/m

σ_{ow}	oil/water interfacial tension, mN/m
θ	contact angle
Φ	potential, kPa
ϕ	porosity

Abbreviations

IFT	Interfacial Tension
JBN	Johnson-Bossler-Nauman
NMR	Nuclear Magnetic Resonance
PV	Pore Volume, m ³
WOR	Water-Oil Ratio

Subscripts

b	brine
g	gas phase
go	gas-oil
j	refers to jth phase
o	oil
og	oil-gas
ow	oil-water

Superscripts

*	normalized
---	------------

STATISTICAL

DF	degrees of freedom
----	--------------------

F	F-distribution
m	population mean
N	number of population
n	number of observations
s	standard deviation
t	t-distribution
x	variable
Z	Fisher's Z transformation

Subscripts

i	ith observation (statistical)
---	-------------------------------

Superscripts

*	tabulated value in statistical distribution (F or t)
-	average value

1. INTRODUCTION

Flow in porous media is a very complex phenomenon and as such cannot be described as explicitly as flow through pipes or conduits. It is rather easy to measure the length and diameter of a pipe and compute its flow capacity as a function of pressure; however, in porous media flow is different in that there are no clear-cut flow paths which lend themselves to measurements.

The analysis of fluid flow in porous media has evolved throughout the years along two fronts - the experimental and the analytical. Physicists, engineers and hydrologists have examined experimentally the behaviour of various fluids as they flow through media ranging from sand packs to fused Pyrex glass. On the basis of their analyses they have attempted to formulate laws and correlations which can then be utilized to make analytical predictions for similar systems.

Over the past three decades, numerical reservoir simulation has gained wide acceptance throughout the petroleum industry, a consequence of three major factors: a) a tremendous increase in computing speed and capacity, resulting in lower unit computing cost, b) improvements in the numerical algorithms for solving partial differential equations; and, perhaps the most important, c) the generality built into reservoir simulators permitting them to model more realistically the wide variety of oil and gas reservoirs.

Petroleum production often involves simultaneous flow of three immiscible fluids through subterranean porous rock formations. Examples of recovery processes involving such three-phase flow include: alternating gas and water injection, steam drive, in-situ combustion, and immiscible gas injection in the presence of mobile water. Thorough analysis of these processes is impossible without reliable three-phase relative permeability data. Reservoir simulation programs incorporate one or several techniques for estimating three-phase relative permeabilities, which permit three-phase simulation studies to be carried out with input of only two-phase relative permeabilities. However, such simulation studies can be no more reliable

than the techniques for estimating three-phase relative permeabilities employed in them. Unfortunately, the reliability of these estimation techniques cannot be tested without the availability of extensive experimental data on three-phase relative permeabilities.

Compared with the wealth of information available in the literature on two-phase relative permeabilities, there is a relative dearth of experimental studies on three-phase flow through porous media. The effect of variables such as wettability, interfacial tension, viscosity ratio, flood velocity and temperature on three-phase relative permeability have not been investigated. There is an obvious need for more experimental investigations of three-phase relative permeabilities to resolve some of the uncertainties concerning the effects of the variables mentioned above.

The reason for this scarcity of experimental data on three-phase relative permeabilities appears to be the effort and time required for such measurements. The only well accepted technique for such measurements is the steady-state method. Between 40 to 60 steady-state measurements are required to fully define the relative permeability characteristics of a given system in one direction of saturation change. It often takes 24 hours or more to reach steady-state conditions for each such measurement. Combined with the time involved in core preparation and periodic extraction to overcome the problem of error accumulation, the total effort involved is indeed formidable. If the hysteresis effects corresponding to various possible directions of saturation change are also to be evaluated, the task becomes even more tedious.

Three-phase relative permeabilities play a central role in the analysis of the steam drive process for heavy oil recovery. Some experimental data are available for three-phase relative permeability at 100°C [Maini et al., 1989]. Unfortunately, no experimental data on three-phase relative permeabilities at other temperatures are available, making it difficult to deduce any effect of temperature on them. Over the past 25 years, a number of studies have reported temperature effects on two-phase relative permeabilities in porous media. Several of these [Maini and Batycky, 1985; Maini and Okazawa, 1987; Maini and Coskuner, 1988;

Torabzadeh and Handy, 1984; Quettier and Corre, 1986; Bennion et al., 1985] report a significant effect of temperature on the oil/water relative permeability. Similar effects can be expected on the two-phase oil/gas relative permeabilities. Three-phase flow is a relatively more complex process. When considering the possible mechanisms of temperature effects on three-phase relative permeabilities, one has to deal with the relative magnitudes of three contact angles (oil-water, oil-gas and water-gas), three interfacial tensions and three viscosity ratios. It is, therefore, probable that the effects of temperature on three-phase relative permeabilities will be more complex than those which pertain to the two-phase case. Whether or not this is the case can only be determined by experimental evaluations of the effects of temperature on three-phase relative permeabilities. Before this can occur, the problem of developing techniques for the reliable measurement of three-phase relative permeabilities at elevated temperatures and pressures has to be addressed.

The objective of this study is to develop and modify an apparatus which is capable of measuring three-phase relative permeabilities at elevated temperatures and pressures, and to investigate the effect of temperature, if any, on three-phase relative permeabilities. Another objective is to use the generated data to test the available models for estimating three-phase relative permeabilities at elevated temperatures and pressures.

2. LITERATURE REVIEW

2.1 Relative Permeability

The concept of relative permeability was introduced in the petroleum industry to describe the relative flow characteristics of two immiscible fluids in porous media, and it was extended to three-phase flow by Leverett and Lewis[1941]. Relative permeability is defined as the ratio of the effective permeability of a fluid at a given value of saturation to the effective permeability of that fluid at 100 per cent saturation. The effective permeability is a measure of the conductance of the porous medium for one fluid when the medium is saturated with more than one fluid[Amyx et al., 1960].

The most widely used equation for flow through porous media is due to Henry Darcy, who derived an empirical relationship based on experimental evaluations. It shows the dependence of flow velocity on both the porous medium and the fluid properties. Assuming homogeneous, linear, steady-state, incompressible and laminar flow for a single fluid:

$$q = -\frac{kA}{\mu} \frac{\partial \Phi}{\partial L} \quad (2.1)$$

where

$$\Phi = P + \rho g z \quad (2.2)$$

is the fluid potential.

Darcy's law, as originally formulated, only applies when the porous medium is fully saturated with a homogeneous, single phase fluid. In petroleum reservoirs, however, the rocks are usually saturated with two or more fluids. It is necessary to generalize Darcy's law by introducing the concept of effective permeability to describe the simultaneous flow of more than one fluid. In the definition of effective permeability, each fluid phase is considered to be completely independent of the other fluids in the flow network. The fluids are considered immiscible, so that Darcy's law can be applied to each fluid phase individually. Thus, Darcy's

law can be restated as follows:

$$q_j = - \frac{k_j A}{\mu_j} \frac{\partial \Phi_j}{\partial L} \quad (2.3)$$

where k_j is the effective permeability to fluid j (oil, water, gas).

The sum of the relative permeabilities of all phases is almost always less than unity because of interference among the phases sharing the flow channels. There are a number of reasons for this interference. One of these reasons is that part of the pore channels available for flow of a fluid may be reduced in size by the other fluids present in the rock. Another reason is that immobilized droplets of one fluid may completely plug some constrictions in a pore channel through which another fluid would otherwise flow. Also, some pore channels may become effectively plugged by adverse capillary forces, if the pressure gradient is too low to push an interface through a constriction. A fourth reason is the trapping of a group of globules that are clustered together and cannot be moved, because the grain configuration allows fluid to flow around the trapped globules without developing a pressure gradient sufficient to move them. This phenomenon is referred to as the Jamin effect [Honarpour et al., 1986].

2.2 Factors Affecting Two- and Three-Phase Relative Permeabilities

Relative permeability is one of the important fundamental transport properties of a porous medium when two or three immiscible fluids are flowing through it. Relative permeability is affected by several factors, such as, wettability, temperature, interfacial tension, viscosity, etc.

2.2.1 Effect of Temperature

Thermal oil recovery processes have become increasingly accepted in the oil industry during the last two decades. While much has been written on heat transfer and fluid flow

mechanisms as well as case history and numerical simulations associated with these processes, there is only limited information on the effect of elevated temperature on the basic petrophysical properties of reservoir rocks. Relative permeability is one of the properties which is important and necessary in describing the mechanisms of fluid flow in porous media. With the introduction of temperature effects, contradictory results were obtained, mainly because different systems were used, and this issue is still controversial.

Relative permeability is usually measured at room temperature conditions. In many cases, relative permeability curves obtained at room temperatures are used to predict performance at reservoir temperature. Many reservoir simulators of thermal processes express relative permeability as a function of fluid saturation only. These practices can lead to an inaccurate or, perhaps, an erroneous forecast of oil recovery [Nakornthap and Evans, 1982]. In their study of steam flooding, Coats et al. [1973] developed a numerical simulation model and then made comparisons of simulation results with several sets of experimental data. They observed a calculated oil recovery curve lying below the experimental curve. After performing many simulation runs with altered data in an attempt to match the calculated oil recovery with the observed one, they concluded that the temperature dependence of relative permeability must be incorporated into the model to properly reproduce the experimental results.

Edmondson [1965] found that a temperature-dependent effect existed in Berea sandstone. In his experiment involving water flooding at elevated temperatures ranging from 75°F (23.9°C) to 500°F (260°C), he showed a change in relative permeability ratio accompanied by a decrease in residual oil saturation with temperature increase. He showed no data for water saturations below 40 percent, and his relative permeability ratio curves show a considerable amount of scatter in the middle saturation range. He concluded that prediction of field hot water floods required displacement data at the actual flood temperature.

Davidson [1969] investigated the temperature dependence of the permeability ratio by conducting isothermal displacements of No. 15 white oil from an unconsolidated sandpack by

either nitrogen, steam, or distilled water; and displacement of water by nitrogen. Values of the water-oil permeability ratio were obtained over the temperature range of 75°F (23.9°C) to 540°F (282°C). At low water saturations, the ratio appeared to be temperature dependent. On the other hand, the gas-oil permeability ratio calculated from a nitrogen-white oil displacement indicated a definite dependence on temperature over the range 75°F (23.9°C) to 500°F (260°C) and over the entire gas saturation range. He also found a decrease in residual oil saturation with temperature increase.

Poston et al.[1970] presented waterflood data for unconsolidated sandpacks containing 80, 99, and 600 mPa.s viscosity oil at temperatures from 70°F (21°C) to 300°F (148.9°C), and observed an increase in the individual relative permeability curves as temperature was increased. Although the water-oil permeability ratio appeared temperature sensitive, no definite trend was found for the change of relative permeability ratio with temperature. They also found an increase in irreducible water saturation and a decrease in residual oil saturation as temperature increased. In addition, a decrease in contact angle for the water-oil-gas system and a decrease in oil-water interfacial tension with increasing temperature were observed. They also pointed out that unconsolidated sands became more water-wet with an increase in temperature.

Sinnokrot[1969] investigated the effect of temperature on capillary pressure curves of limestones and sandstones, and found that limestones exhibited negligible temperature sensitivity. For sandstones, however, he found that hysteresis between drainage and imbibition capillary curves gradually decreased with temperature until it was virtually absent at 300°F (148.9°C). He calculated water and oil relative permeabilities from the capillary pressure data and observed an increase in oil relative permeability and a decrease in water relative permeability as temperature increased. In addition, he reported that, as temperature increased, sandstones became more water-wet, irreducible water saturation increased and residual oil saturation decreased.

Weinbrandt et al.[1975] in their study of the temperature effect on relative permeability and absolute permeability for Boise sandstone showed that absolute permeability decreased with a temperature increase. The oil relative permeability increased with increasing temperature while the water relative permeability variation appeared inconclusive. They hypothesized that thermally induced mechanical stress caused by thermal expansion of rock grains, rather than interfacial rock-fluid forces, may be the source of the observed changes in absolute and relative permeabilities. Again, in their study, an increase in irreducible water saturation and a decrease in residual oil saturation accompanied an increase in temperature. They showed that a moderate 100°F (37.8°C) temperature rise in a water-oil system can nearly double the irreducible water saturation and reduce the residual oil saturation by more than half. de Haan and van Lookeren[1969] reported that in their steam stimulation project, only about one-fourth of the injected steam was recovered as water production. The connection between this observation and the above mentioned effect of temperature on irreducible water saturation is quite apparent.

Casse and Ramey[1979] conducted an experimental study which showed that the temperature effect upon the absolute permeability of consolidated sandstones depends on the nature of the saturating fluid. In the case of water saturated cores, absolute permeability decreased with increasing temperature. Over a span of 70°F (21°C) to 325°F (162.8°C), an absolute permeability reduction of up to 65 percent was observed. For oil saturated samples, a slight increase in permeability with increasing temperature was observed in the low temperature range, followed by a decrease and an apparent stabilization. However, this thermal sensitivity barely exceeded the range of experimental error. On the other hand, absolute permeability to gas was found to be independent of temperature; that is, the Klinkenberg extrapolated absolute permeability was the same at all temperatures. They also found that, regardless of the nature of the saturating fluid, the level of confining (or overburden) pressure affected permeability in the same manner; that is, permeability decreased with increasing

confining pressure. For thermally sensitive water saturated cores, increasing the confining pressure has the additional effect of intensifying the temperature dependence. In light of their results, they concluded that the temperature effect on absolute permeability was not caused by changes in the physical properties of the fluids, such as viscosity and density, because fluids with large viscosity and density contrasts such as oil and gas, yielded essentially the same effects. The temperature effect was not solely caused by thermally-induced mechanical stresses since no significant absolute permeability changes were found for oil or gas flow. Instead, the unique results obtained for water flow suggested that a combination of rock-fluid interaction and thermally-induced mechanical stresses was responsible for the observed changes in absolute permeability.

Lo and Mungan[1973] measured oil and water relative permeabilities in both oil-wet and water-wet systems at elevated temperatures. The results were similar in both the oil-wet and water-wet systems; that is, higher temperatures caused an increase in oil relative permeability and a higher rate of increase in water relative permeability with saturation. Higher irreducible water saturation and lower residual oil saturation were also found to accompany an increase in reservoir temperature.

In his modelling of the temperature effect, Ehrlich[1970] reported that with an increase in temperature, water wettability increased as the oil-water-rock contact angle was reduced to zero. He observed that the water-oil relative permeability ratio at a given saturation increased with temperature for low residual oil porous media and decreased with temperature for high residual oil materials.

Sufi et al.[1982] found that relative permeabilities obtained with clean oil and water in unconsolidated clean Ottawa sand were independent of temperature between 70°F (21°C) and 186°F (85.6°C). They concluded that the decrease in 'practical' S_{wr} was due to the reduction in the viscosity ratio and the 'apparent' increase in S_{wi} was the result of a decrease in the viscous force provided by oil which, in turn, is caused by the viscosity reduction with

temperature.

Miller and Ramey[1985] performed dynamic displacement tests on unconsolidated and consolidated sand cores using water and a refined oil and observed no changes with temperature in either residual saturations or relative permeability curves. Only endpoint relative permeabilities and saturations were compared at 97°F (36°C) and 199°F (92.8°C), which in fact showed some temperature effect on oil relative permeabilities at irreducible water saturations. They postulated that the results of the previous researchers may have been affected by viscous instabilities, capillary end effects and/or material balance measurements difficulties.

Maini and Batycky[1985] investigated the effect of temperature on horizontal and vertical relative permeabilities of a heavy oil/water system. Their results showed an increase in S_{wi} , and a decrease in S_{or} to a minimum value and changes in relative permeability curves with increasing temperature.

Polikar[1987] undertook an extensive study to determine bitumen-water relative permeability over a large temperature range (100°C to 250°C). The experiments were conducted with both clean and reservoir sands. He found that there was no significant temperature effects for the Athabasca bitumen-water system in clean or field sands. He concluded that the reason for this was due to the lack of reactivity of the fluid-fluid-solid combinations.

2.2.2 Effect of Wettability

The microscopic distribution of fluids in a porous medium is greatly influenced by the degree of rock preferential wettability. The fluid distribution in virgin reservoirs under strongly water-wet and strongly oil-wet conditions has been described by Pirson[1958]. In a strongly water-wet reservoir, most of the water resides in dead-end pores, in small capillaries and on the grain surface. In strongly oil-wet reservoirs, water is in the centre of the large pores as discontinuous droplets, while oil coats the surfaces of the grains and occupies smaller

capillaries.

Under strongly water-wet conditions, the effective permeability to the nonwetting phase at irreducible water saturation is approximately equal to the absolute permeability of the rock. On the other hand, in strongly oil-wet systems, the effective permeability to oil at irreducible water saturation is greatly reduced by the water droplets in the larger pores. Raza et al.[1968] stated that in some oil-wet reservoirs, water occupies some of the finer pores and is trapped as droplets in the larger ones. In strongly water-wet reservoirs, water traps oil in the larger pores as it advances along the walls of the pore, while in strongly oil-wet reservoirs, water moves in the large pores and oil is trapped close to the walls of the pores[Raza et al., 1968].

Schneider and Owens[1970] recognized the fact that rock type appears to have less influence on flow relationships than does rock wetting preference. However, this may not be the case for heterogenous rocks or mixed wettability systems. Owens and Archer[1971] also confirmed the importance of preferential wettability on multiphase flow in porous media.

Some investigators[Rathmell et al., 1973] have found that relative permeability becomes progressively less favourable to oil production as a rock becomes less water-wet. The residual oil saturation increases as a rock becomes less water-wet. Others have shown that weakly water-wet cores have more favourable relative permeability curves and lower residual oil saturations than strongly water- or oil-wet rocks. Conceptually, this latter behaviour seems reasonable since the capillary forces in strongly water-wet cores are strong. The oil may be bypassed and trapped in larger pores by the tendency of a water-wet core to imbibe water into the smaller capillaries. The bypassed oil in the large pores is then surrounded by water and is immobile, except at very high pressure gradients.

Stegemeier and Jensen[1959] and McCaffery and Bennion[1974] reported that wettability alterations over a relatively wide range produced a negligible effect on the relative permeability curve. However, other workers did not confirm this finding. Treiber et al.[1972]

found that relatively small variations in wettability produce large effects on the relative permeability curve.

Anderson[1987] compiled a thorough literature survey covering the effects of wettability on relative permeability. The wettability of a core will strongly affect its waterflood behaviour and relative permeability. Wettability affects relative permeability because it is a major factor in the control of the location, flow, and distribution of fluids in a porous medium. In uniformly or fractionally wetted porous media, the water relative permeability increases and the oil relative permeability decreases as the system becomes more oil-wet. In a mixed wettability system, the continuous oil-wet paths in the larger pores alter the relative permeability curves and allow the system to be waterflooded to a very low residual oil saturation after the injection of many PV of water. The most accurate relative permeability measurements are made on native-state core, where the reservoir wettability is preserved. Serious error can result when measurements are made on cores with altered wettability, such as cleaned core or core contaminated with drilling-mud surfactants. Craig[1973] presented several rules of thumb that indicate the differences in the relative permeability characteristics of strongly water-wet and strongly oil-wet cores. Mungan[1972] showed that at all water saturations, the water/oil relative permeability ratio is higher for a preserved core with reservoir fluids than for a clean core with purified fluids. The water/oil flow characteristics of such reservoir cores cleaned to a strongly water-wet conditions could be quite misleading.

2.2.3 Effect of Interfacial Tension

Limited data exist in the literature on the effect of interfacial tension (IFT) on relative permeability curves. Leverett[1939] reported a tendency for the water/oil system in unconsolidated sands to exhibit higher relative permeabilities when the IFT was lowered from 24 to 5 mN/m. Mungan[1966] investigated interfacial effects on oil displacement in Teflon cores. From his results, a decrease in the wetting/nonwetting relative permeability ratio could

be found with decreasing IFT from 40 to 5 mN/m. Lefebvre du Prey[1973] explained the effect of IFT on relative permeability through the capillary number.

Gilliland and Conley[1975] reported that in a low-tension system ($0.01 < \text{IFT} < 0.19$ mN/m), relative permeability to oil shifted toward higher water saturations and the ultimate S_{or} decreased to zero. The wetting phase relative permeability did not change. Talash[97] showed that in a water/oil low-tension system, relative permeability curves for both phases increased at a given saturation and S_{or} decreased with decreasing IFT. Hysteresis was not observed in his relative permeability curves. Batycky and McCaffery[1978] presented steady-state relative permeability data for different levels of IFT in sandpacks. Their data show a decrease in irreducible water saturation and changes in relative permeabilities with decreasing tensions.

Bardon and Longeron[1980] investigated the effect of IFT on gas/oil relative permeability curves and observed that they were strongly affected by low IFT's. Similar results have been reported by Asar and Handy[1983] for a gas condensate system near the critical point.

Amaefule and Handy[1980] found that oil/water relative permeabilities of consolidated sands were greatly affected by IFT values lower than 0.1 mN/m. Their results showed that both k_{ro} and k_{rw} increased, while the end point saturations decreased and hysteresis diminished with decreasing IFT.

Studies by Fulcher et al.[1983] and Harbert[1983] indicated that relative permeability curves are influenced by IFT values below 2 mN/m. They reported the effect of IFT on relative permeability curves and end-point saturations in terms of the capillary number.

Torabzadeh and Handy[1984] obtained water/oil relative permeabilities of high- and low-tension systems at elevated temperatures. They investigated the combined effects of temperature (22 to 175°C) and interfacial tension (33.6 to 0.015 mN/m). They observed that water/oil relative permeability curves are affected by temperature, especially at low interfacial tensions. For high tension systems ($\text{IFT} > 20$ mN/m), S_{wi} increased while S_{or} decreased. Also

the water/oil relative permeability ratio decreased and shifted toward higher water saturations. For low-tension systems ($0.01 < \text{IFT} < 0.19 \text{ mN/m}$), S_{wi} did not change significantly while S_{or} decreased. On the other hand, the water/oil relative permeability ratio decreased at a given saturation and shifted toward higher water saturations. Its curvature increased with increasing temperature. They also observed hysteresis which decreased with increasing temperature and decreasing IFT and disappeared at elevated temperatures and ultra low-tensions.

2.2.4 Effect of Viscosity

Leverett[1939] and Leverett and Lewis[1941] investigated the effect of viscosity variation of an oil-water mixture on the relative permeability of artificially compacted sands with 41% porosity and 3.2 to 6.8 D of absolute permeability. They found no systematic variation in relative permeability when the oil viscosity was varied from 0.31 mPa.s (hexane) to 76.5 mPa.s (lubricating oil) and the water phase viscosity was varied from 0.85 mPa.s to 32.2 mPa.s. Viscosity ratios employed in the study ranged from 0.057 to 90. Their experiments were performed under steady-state flow at low pressure gradients.

Wyckoff and Botset[1936] found that moderate variations in viscosities of the fluid phases in unconsolidated sand packs with permeabilities ranging from 3.2 to 6.0 D failed to produce any change in the relative permeability values. In their experiments, a mixture of water and carbon dioxide was employed and water viscosity was adjusted between 0.9 to 3.4 mPa.s by addition of a sugar solution to the water.

Richardson[1957] found that the water-oil relative permeability ratio is independent of fluid viscosity when the oil viscosity varied from 1.8 to 151 mPa.s. Johnson et al.[1959] confirmed these results for displaced/displacing viscosity ratios up to 37. Levine[1954] found that the relative permeability of a sandstone sample was independent of viscosity ratio in the range of 1.92 to 22.6 mPa.s. Craig[1952] reported that the gas-oil relative permeability ratio of a Nellie Bly sandstone sample with 824 mD permeability and 28.1% porosity showed no

evident variation for oil viscosities in the range of 1.4 to 125 mPa.s.

Sandberg et al.[1958] found that oil and water relative permeabilities of a uniformly saturated core are independent of the oil viscosity in the range of 0.398 to 1.683 mPa.s. Donaldson et al.[1966] and Geffen et al.[1952] also concluded that relative permeability is independent of viscosity as long as the core wettability is preserved. Wilson[1956] found that a 5000 psi (34.5 kPa) fluid pressure which caused the kerosene viscosity to increase from 1.7 to 2.7 mPa.s and the water viscosity to increase by 1% did not produce any significant effect on oil and water relative permeability values. Muskat et al.[1937] reported that the effect of viscosity on relative permeability of an unconsolidated sand was very small and within the limits of experimental accuracy.

Krutter and Day[1943] used methane and air as the nonwetting phase in a two-phase system of oil and gas. The gas was injected into cores saturated with oils with viscosities ranging from 2 to 100 mPa.s. They found that the air relative permeability values were slightly less than those for methane.

Saraf and Fatt[1967] applied Darcy's law to each of the phases of a multi-phase system and concluded that relative permeability is independent of viscosity. The Saraf and Fatt equation is based on the assumption that different phases flow in different capillaries and do not come in contact with each other.

Yuster[1951], however, concluded that relative permeability values for the systems he studied were markedly influenced by a variation in viscosity ratio, increasing with an increase of the ratio. This conclusion supports the work of Morse et al.[1947]. Odeh[1959] expanded Yuster's work and concluded that the nonwetting phase relative permeability increases with an increase in viscosity ratio. He found that the magnitude of the effect on relative permeability decreases with increases in the single-phase permeability (absolute permeability). Odeh found that the deviation in the nonwetting-phase relative permeability is increased as the nonwetting phase saturation is increased, with the deviation reaching a maximum at the nonwetting-phase

residual saturation. He also concluded that the wetting-phase relative permeability is not affected by variation in the viscosity ratios. Odeh stated that the effect of viscosity ratio on relative permeability could be ignored for samples with single-phase permeabilities greater than 1 D.

Downie and Crane[1961] reported that oil viscosity could influence the oil relative permeability of some rocks. Later, they qualified their statement by saying that once an increased relative permeability is obtained by employing a high viscosity oil, it may not be lost by replacing this oil with one of lower viscosity.

Lefebvre du Prey[1973] made a systematic study of the effect of the ratio of capillary to viscous forces, $\sigma \cos \theta / \mu v$, where σ represents the interfacial tension expressed as mN/m; θ represents the contact angle; μ represents the viscosity expressed as mPa.s; and v represents the fluid velocity expressed as metres per second, on relative permeability by simultaneously varying the interfacial tension, viscosity and velocity. He found that the relative permeability curve is influenced by the viscosity ratio when the wetting phase is displaced by the nonwetting phase.

Ehrlich and Crane[1969] concluded that the imbibition and drainage relative permeabilities, under a steady-state condition of flow, are independent of viscosity ratio. However, they found that the irreducible wetting-phase saturation following a steady-state drainage, when the interfacial effect predominated over the viscous and gravitational effects, decreases with an increase in the ratio of the nonwetting to the wetting-phase viscosities.

Danis and Jacquin[1983] showed that oil relative permeabilities at residual water saturation may depend on oil viscosity under various conditions and that the influence of viscosity on oil relative permeability seemed to be greater as the porous medium became more complex.

An assumption that the relative permeability values are independent of viscosity implies that the system can be represented by a bundle of parallel, noninterconnecting capillary tubes,

each of which is filled with either the wetting or the nonwetting phase alone. Thus, the nonwetting phase flows through the larger channels while the wetting phase flows through the smaller capillaries. However, this model does not completely represent the conditions in porous media. An alternative model is the simultaneous flow of two or three immiscible fluid phases in the larger capillaries.

A flow picture more compatible with the present knowledge of fluid behaviour is a combination of the two models described above, with one dominating over the other depending primarily on wettability. Odeh[1953] believed that the fluid phases did not flow in separate capillaries of porous media, as Leverett postulated, and further stated that the wetting phase moves microscopically in a sort of sliding motion imparted to it by the shear force caused by the motion of the nonwetting phase. From this model, he concluded that a decrease in interstitial wetting-phase saturation can be developed as a result of an increase in viscosity, thereby affecting the relative permeability values.

In view of the diverse opinions which have been expressed by various investigators concerning the influence of viscosity on relative permeability, it seems best to conduct laboratory relative permeability experiments with fluids which do not differ greatly in viscosity from the reservoir fluids.

Table 2.1 presents a summary of the observations reported in the literature for unconsolidated and consolidated porous media.

Table 2.1 :Summary of Temperature Effects on Relative Permeability Studies

Author(s)	Porous Media	Experimen- tal Method	Temperature Effect on	
			end point saturations	relative permeability
Wilson (1956)	Sandpack	Steady-State	no	no

Table 2.1 :Summary of Temperature Effects on Relative Permeability Studies.....Cont'd

Author(s)	Porous Media	Experimen- tal Method	Temperature Effect on	
			end point saturations	relative permeability
Edmondson (1965)	Berea sandstone	Dynamic	yes	yes
Combarous & Pavan(1968)	Sandpack	Steady-State	yes	N/A
Davidson (1969)	Sand & gravel pack	Dynamic	N/A	yes
Sinnokrot (1969)	Sandstone	Capillary pressure	yes	yes
Poston et al. (1970)	Sand pack	Dynamic	yes	yes
Lo & Mungan (1973)	Teflon	Steady-State	yes	yes
Weinbrandt et al. (1975)	Boise sandstone	Dynamic	yes	yes

Table 2.1 :Summary of Temperature Effects on Relative Permeability Studies.....Cont'd

Author(s)	Porous Media	Experimental Method	Temperature Effect on end point saturations	relative permeability
Sufi et al. (1982)	Sand pack	Dynamic	no	no
Torabzadeh & Handy (1984)	Berea sandstone	Steady-State	yes	yes
Bennion et al. (1985)	Sandstone	Dynamic	yes	yes
Maini & Batycky (1985)	Sandstone	Dynamic	yes	yes
Miller and Ramey (1985)	Berea sandstone	Dynamic	no	no
Maini & Okazawa (1986)	Sandstone	Dynamic	no	yes
Polikar (1987)	Sandpack	Steady-State	no	no

2.2.5 Viscous Coupling

The standard description of two and three-phase flow in porous media is based on a generalization of Darcy's law. This approach assumes that the fluid/solid and fluid/fluid interfaces should act in the same way, which is obviously not true.

Bourbiaux and Kalaydjian[1990] and Bentsen and Manai[1991] have conducted flow experiments involving cocurrent and countercurrent two-phase flow. They found that the magnitude of countercurrent relative permeability, at a given saturation, was always less than that of the associated cocurrent relative permeability. They concluded that viscous coupling is the origin of this difference. Kalaydjian[1990] developed an extended formulation of Darcy's two-phase law which leads to a matrix of relative permeabilities. Nondiagonal coefficients of this matrix are due to the viscous coupling exerted between fluid phases, while diagonal coefficients represent the contribution of both fluid phases to the total flow, as if they were alone. He also found the coupling terms to be significant as compared with the diagonal terms. Rose[1988] also came to the same conclusions. Bentsen[1993] has explored the significance of neglecting the viscous coupling effect by estimating the relative error incurred when proper account of these effects is not undertaken. He has shown, by investigating several one-dimensional problems, that relative errors of the order of forty percent are introduced when viscous coupling effects are neglected.

Investigations concerning viscous coupling are still confined to two-phase flow. No study encompassing viscous coupling in three-phase flow has so far been reported. The reason is the complex nature of the experiment involved and the difficulty in formulating the phenomena of three-phase flow through porous media.

2.3 Techniques for Three-Phase Relative Permeability Measurements

There are essentially three means by which three-phase relative permeability data can be measured in the laboratory. They are (1) direct measurement in the laboratory by a steady-

state fluid flow process, (2) measurements in the laboratory by a displacement or unsteady-state process, and (3) the centrifuge method. The most frequently used method is the steady-state flow test [Maini, 1990].

There are numerous variations of the steady-state method which can be used in the laboratory to measure relative permeability; essentially all of them depend upon the following technique. A small core sample is chosen and prepared for the test. It is mounted in lucite or in a pressurized sleeve. The phases oil, water, and gas which are to be used in the test are introduced simultaneously at the inlet end through different piping systems. Most tests are started with the core sample 100 per cent saturated by the wetting phase, and the tests are known as desaturation tests. The fluids are introduced at a predetermined fluid ratio and are flowed through the core until the produced ratio is equal to the injected ratio and also the pressure drop across the test sample stabilizes. At this time, the core system is considered to be in a steady-state flow condition and the existing saturations are considered to be stable.

The saturation of the various fluids is determined using one or a combination of the following techniques: (a) A volumetric balance is maintained of all fluids injected and produced from the sample; (b) electrodes are inserted in the test section, and the saturations are determined by measurement of the core resistivity; (c) the core section is removed and weighed to determine the saturation condition; and (d) X-ray attenuation method is used with a combination of tracer containing fluids in the core. Once the saturation and pressure drop have been measured by one of the above methods, the relative permeability of the flowing phase can be calculated at these saturation conditions. The fluid injection ratio is increased, removing some more of the wetting phase, until once again the system reaches a steady-state condition. This process is continued until a complete relative permeability-saturation curve is obtained.

An alternative method is to use the resaturation process where the test sample is originally at minimum oil saturation. In this method, the injection ratios start out at high oil -

phase values and decline to zero per cent oil phase value.

One of the major problems in the steady-state method is the capillary effect at the outflow end of the core. The term "end effects" refers to a discontinuity in the capillary forces of the system existing at the outflow end of the core. In the body of the sand, capillary forces act uniformly in all directions, thus cancelling each other. But at the end of the core, they do not cancel. As a result, the wetting phase is initially prevented from coming out of the porous medium. Therefore, the wetting phase saturation builds up near the inside boundary of the porous medium. This buildup of wetting phase saturation can cause serious errors, in relative permeability measurements, if core average saturations and pressure drops are used for relative permeability calculations. For reliable relative permeability measurements, it is necessary to either minimize these end effects or, alternatively, to account for them in the calculation of relative permeability. Several methods have been proposed in the literature for this purpose. These range from the simple technique of using high flow rates to elaborate techniques employing in-situ saturation measurements.

The capillary pressure or Hassler[1944] method is based on the idea that the end effects will not arise, if the fluids do not have to come out of the porous medium simultaneously from the same location. To ensure this condition, semi-permeable membranes are provided at each end to produce different fluids from different outlets. Using this technique for three-phase measurements will require three different semi-permeable membranes, each permeable to one fluid only. If only two membranes, one permeable to brine and the other permeable to oil and gas, are used, the end effects would be reduced but not completely eliminated. The method is quite cumbersome and is currently not very popular. Finding suitable membranes for three-phase measurements and maintaining their semi-permeable character over extended periods can also present some problems.

The most commonly used method appears to be the Penn-State method[Morse et al., 1947], which uses separate inlet and outlet sections of similar core material. Measurements

of saturation and pressure drop are made on the central piece only which is the core to be tested. This method should work reasonably well in a three-phase system also, provided a perfect capillary contact can be ensured between the adjoining cores. This method of minimizing end effects makes the saturation measurement somewhat more difficult. Unless in-situ techniques are used, the saturation measurement requires removing the test core from the core holder for each measurement.

An interesting technique, which has received very little attention in the literature, was suggested by Richardson and Perkins[1957]. Their method relies on attaching a narrow packed tube to the outflow end of the core. Because of the very high flow rate in the narrow section, the end effects remain confined to the narrow tube section.

The gas-drive displacement technique of testing is essentially a nonsteady-state flow process. The sample is originally 100 per cent saturated with the liquid phases, and instead of injecting all the fluids, only gas is injected into the core.

The gas-displacement process for determining relative permeabilities as proposed by Sarem[1966] is dependent upon the frontal advance fluid-flow concept. The procedure for performing a gas-displacement test is relatively simple and fast. The procedure is essentially as follows: a sample is selected, and its physical properties of permeability, bulk volume and porosity are determined. The sample is properly mounted in a holder (similar to those described in the steady-state tests), and 100 percent saturated with the liquid phases, which are normally oil and water. The sample is desaturated by injecting gas at one end and producing all the fluids at the other end of the sample. In the calculations of the data obtained from such a test, there are essentially three necessary conditions or assumptions which must be satisfied. First, the pressure drop across the core must be large enough to make any capillary end effect negligible. Second, the gas saturation can be described at a mean value of pressure (average of the inlet and outlet pressures). Third, flow is horizontal, and the core sample is small enough and the test time is short, so that all effects of gravitational forces can be neglected.

If these three conditions are satisfied, then it is necessary to measure only the following quantities during the test: (1) the cumulative gas injected as a function of time and (2) the cumulative oil and water produced as a function of time.

van Spronsen[1982] proposed a new method for fast and easy measurement of three-phase relative permeabilities using centrifuge equipment. In this method, a liquid (usually oil and water) saturated sample is placed in an air-filled core holder and subsequently rotated at a constant speed in a centrifuge. The production from the sample is collected in a graduated transparent tube. The production as a function of time is usually measured by taking photographs of the transparent tube.

The water and oil saturations at the outflow end of the sample change continuously during drainage of the liquids resulting in measurements along a trajectory in the saturation ternary diagram. This trajectory depends on the initial conditions, and the mobility of the phases. Proper choice of initial conditions and fluid viscosities can insure sufficient coverage of the ternary diagram to map out the three-phase liquid isoperms.

2.4 Experimental Studies of Three-Phase Relative Permeabilities

Leverett and Lewis[1941] were the first to measure three-phase relative permeabilities in an unconsolidated sand-pack using the steady-state technique. They used the resistivity technique to determine the brine saturation while pressure-volume measurements were used to determine the gas saturation. Oil saturation was calculated from material balance. End effects were assumed to be negligible because of the relatively high pressure gradients used in the experiments (50 to 328 mmHg). They considered dead space in the cell to be the largest source of error (up to 6%) followed by the errors due to the failure to reach equilibrium. The oil and gas saturations would be affected more by the dead space. It is probable that when all possible sources of errors are added, their gas saturation measurements could be in error by 8%. The oil saturation measurement was the least reliable because it contained errors from

both the water and the gas saturations.

The conclusions reached by Leverett and Lewis were that the water relative permeability was a function of its own saturation, while gas and oil relative permeabilities varied with the saturation of all the fluids. The gas isoperms show only a moderate curvature. In view of the possible error in the gas saturation measurement and scatter of the experimental data points, the same data could be represented by straight lines. The oil isoperms show more pronounced curvature. So, the results reported in this paper are consistent with strongly water-wet behaviour; that is, the relative permeabilities of water and gas are functions of their own saturations while the oil relative permeability depends on all three saturations.

Three-phase relative permeabilities reported in a paper by Caudle et al.[1951] were measured in a consolidated sandstone using a three piece core assembly with saturations and pressure drop measured on the central piece only. Saturations were obtained by weighing and vacuum distillation of the test core after reaching steady-state. The authors described the reported results as preliminary and conceded that not enough three-phase data were gathered to permit a complete description of the behaviour. Their results show that the relative permeabilities of all three phases vary with all three saturations. The degree of curvature was smallest in the gas isoperms and largest in the oil isoperms. It is difficult to assess the magnitude of errors involved in these measurements because insufficient details of the procedure have been reported. The possible sources of errors include the capillary end effects and changes in saturation during removal of the core from the core holder during weighing and vacuum distillation.

Corey et al.[1956] measured three-phase relative permeabilities in water-wet Berea sandstone cores using CaCl_2 brine as the wetting phase. Nine different cores were used in the study and the results obtained on most of these were combined to assess the overall relative permeability behaviour. Capillary barriers were used to maintain constant water saturation while the saturations of oil and gas were varied. The water isoperms presented in this paper

were drawn by assuming that the water relative permeability in three-phase flow is a function of its own saturation only and is therefore the same as in two-phase flow. The saturation history represented by these measurements is in the direction of decreasing oil saturation with gas saturation increasing and water saturation being held constant. They found that the gas relative permeability was a function of gas saturation alone. The oil relative permeabilities were found to vary with both oil and water saturations, the isoperm lines being concave towards the oil apex. The oil relative permeability at a given oil saturation was found to increase with increasing water saturation.

Reid[1956] conducted three-phase relative permeability measurements in high permeability (31 darcy) sand packs using the single-core steady-state technique. Saturation and pressure drop measurements were obtained away from the inlet and outlet ends to overcome the capillary end effects. Water saturation was obtained by resistivity measurements and the gas saturation was measured by a gamma ray attenuation technique. Hysteresis effects were ignored. Electrical conductivity measurements were also found to be troublesome due to electrode corrosion. It is, therefore, probable that these measurements were no more accurate than the previous studies. His results show that relative permeabilities of all three phases vary with saturations of all three fluids. In addition, his results showed that the oil relative permeability in the high oil saturation range at a given oil saturation was somewhat higher when both gas and oil were present as compared with the two-phase situation. At low oil saturations, the oil relative permeability appeared to increase with increasing water saturation. The water and gas isoperms were concave towards their own apexes. The deviations of isoperms lines for gas and water from lines of constant saturation were within the $\pm 5\%$ PV range. Therefore, a $\pm 5\%$ error in saturation measurement would be sufficient to make the observed curvature insignificant.

In an attempt to improve the accuracy of saturation measurements, Snell[1962] employed a radio frequency RCL circuit for the water saturation measurements and a neutron

bombardment method for the gas saturation measurement. Three-phase relative permeability measurements were carried out in a 120 cm long unconsolidated sand core of 7.1 darcy permeability. Ten equally spaced pressure taps were used for monitoring pressure drops in different sections of the core and the relative permeabilities were calculated from measurements of saturation and pressure drops over one or two segments of the core displaying uniform water saturation. Snell estimated the possible saturation errors to be $\pm 2\%$. His results show that relative permeabilities of all three phases were functions of saturation of all fluids. However, the curvatures in the gas and water isoperm lines were much smaller as compared to those in the oil isoperms. Water isoperms were found to be concave towards the 100% water apex. These water isoperms show that water relative permeability at a fixed water saturation increases as one moves away from the oil/water axis; that is, at a fixed water saturation, some oil is replaced by gas. Oil isoperms were also found to be convex towards the 100% oil apex. Oil relative permeability was lowest when both water and gas were present in roughly equal amounts.

The saturation measurement techniques used in this work should have provided reasonably accurate data. A large number of measurements were carried out on the same core. It is likely that the core properties, such as absolute permeability and wettability, could have changed during the course of this investigation. Apparently, the absolute permeability was measured only at the beginning of the flow tests. In view of these uncertainties, these measurements could also be unreliable.

Sarem[1966] proposed an unsteady-state method for measuring three-phase relative permeabilities based on an extension of Welge's method. Unfortunately, the equations used for calculating relative permeabilities were developed on the basis of the assumption that the relative permeability of all the phases are functions of the corresponding individual phase saturations only. He also neglected capillary and gravity effects. This foreordains the isoperms to be straight lines parallel to lines of constant saturation. It is interesting to note that when

tests in Berea sandstone were repeated with different starting water saturations, both water and oil relative permeabilities changed significantly while the gas relative permeability was not significantly affected. Since the method proposed by Sarem is based on questionable assumptions, the data reported by him cannot be considered useful for testing prediction techniques.

Three-phase relative permeabilities reported by Donaldson and Dean[1966] also were measured by an unsteady-state technique involving displacement of water and oil by gas injection. Berea sandstone and Arbuckle limestone were used as the porous media. An extension of Welge's formulation was used for calculating relative permeabilities. Unfortunately, details of the calculation scheme were not included in the report. It is, therefore, not possible to comment on the validity of the assumptions involved in the calculations. Hysteresis effects were ignored and capillary effects were assumed to be negligible due to the high gas injection rates used. Unlike Sarem[1966], the relative permeabilities in this study were found to be functions of all three fluid saturations. There are reasons for questioning the reliability of the three-phase relative permeabilities reported in this paper. The calculation scheme used was not discussed fully and may have involved unsubstantiated assumptions. Sarem found that the starting saturation had a strong influence on the oil and water relative permeability curves determined from similar experiments. Therefore, some of the curvature in the relative permeability curves presented by Donaldson and Dean could have resulted from a similar effect of different starting saturations.

The nuclear magnetic resonance technique was used for saturation measurement by Saraf and Fatt[1967]. The experiments were conducted in strongly water-wet Boise sandstone cores and hysteresis was avoided by using a fresh core for each set of steady-state tests. Pressure drop and saturations were measured away from the ends to minimize the end effects. The tests were run in such a way that the saturation of water was held constant by maintaining a constant water injection rate and constant differential pressure. Oil and gas

saturations were varied and NMR measurements were used to measure the oil saturation. Water saturation was determined by material balance prior to gas injection and the gas saturation was determined by assuming that the water saturation did not change. They estimated that the errors in water and gas saturation measurements were of the order of $\pm 2\%$. Their results show that water and gas relative permeabilities were functions of their own saturations only while oil permeability varied with all saturations. The oil isoperm lines were slightly convex towards the 100% oil apex.

Schneider and Owens[1970] performed steady-state and unsteady-state tests on a variety of carbonate and sandstone samples. They found that the relative permeability to oil during an imbibition process in a water-wet system is insensitive to the presence of a flowing gas phase when the gas saturation is increasing, and depends primarily on its own saturation. The presence of residual oil significantly reduces the gas relative permeability in a water-wet system. The gas relative permeability in an oil-wet system is insensitive to the presence or absence of a residual oil saturation. They also found that the non-wetting relative permeability-saturation relationship in three-phase flow depends on the saturation history of both the non-wetting phases and on the saturation ratio of the second non-wetting phase and the wetting phase. In some cases the three-phase values are lower than the two-phase values due to either trapping of a given non-wetting phase or mutual flow interference between the non-wetting phases when both are flowing.

In the study by Saraf et al.[1982], the three-phase relative permeabilities were measured in Berea sandstone using both the steady-state and the unsteady-state technique based on Sarem's[1966] work. In this work, the calculations of relative permeabilities from the unsteady-state displacement data were based on assumptions similar to those in Sarem's paper but with one difference. The assumption that oil relative permeability is a function of oil saturation alone was applied only over a small saturation range. This will be equivalent to replacing the oil isoperms with a collection of small straight line segments parallel to the

constant oil saturation lines. The relative permeabilities calculated from this procedure were found to be similar to the steady-state values. For the steady-state tests, oil and water were circulated in closed loops containing a windowed cell and the saturations were measured by material balance.

The results of this study again showed that, in strongly water-wet systems, the water relative permeability is a function of water saturation only. The gas relative permeability was found to be a function of gas saturation only as long as the direction of the S_g variation remained the same. Significant hysteresis effects were found in the gas relative permeability. The oil relative permeability was found to be a function of both oil and gas saturations and it was also affected by the direction of the gas saturation change. The curvature in the oil isoperm lines was predominantly concave towards the 100% oil apex, although at low oil saturations some of the lines showed a point of inflection.

In the study by Oak et al.[1988], three-phase relative permeabilities were measured by the steady-state technique using the Penn-State method for overcoming capillary end effects. Tests were conducted in fired Berea sandstone cores. Dual energy X-rays were used to measure all three saturations. X-ray absorbing tracers were dissolved in the liquids to enhance measurement accuracy. Two types of saturation histories were investigated. In the first set of experiments, both oil and water saturations were decreasing and gas saturation was increasing. In the second type of saturation history, gas saturation was decreasing while oil and water saturations were increasing. The core was cleaned after each displacement sequence and its absolute permeability was measured periodically and was found to decrease continuously during the year over which the experiments were undertaken.

The results of this investigation are similar to those reported by Saraf et al.[1982]. The oil isoperms show more complex behaviour including some points of inflection. The experimental data were compared with Stone's prediction models. The predicted values were significantly different from the measured values.

Even though very sophisticated experimental techniques were used in this study, the results still show scatter in the data. The authors did not attempt to draw smooth oil isoperms on the basis of the experimental data.

Maini et al.[1989] measured three-phase relative permeability by the steady-state method in an unconsolidated sandpack at elevated temperature and pressure. The end effect was minimized by using high flow rates in a long core. De-ionized water, nitrogen gas and heavy mineral oil were flowed through the core. Flow rates of water and gas were increased and that of oil was decreased until the flood out point was reached. They conducted both imbibition and drainage experiments in the water-wet sandpack at 100°C.

The conclusions reached by them were that both the water and gas relative permeabilities were a function of their own saturation, while oil relative permeability varied with the saturations of all fluids. They found that the oil isoperms were concave towards the oil apex in both directions of saturation change.

A centrifuge method has been presented by Spronsen[1982] for three-phase relative permeability measurements. It is similar to the unsteady-state method except that the fluids are mobilized by centrifugal forces. The analysis of the fluid production data to calculate relative permeabilities is based on simplifying assumptions. The centrifugal force is assumed to be constant along the length of the core and the capillary pressure is neglected in the analysis. The assumption of negligible capillary pressure is generally not valid in such experiments.

Grader and O'Meara[1988] used three immiscible liquids to conduct three-phase relative permeability experiments using the dynamic displacement method. The reason for using three immiscible liquids was to reduce capillary end effects and viscous fingering. They derived an extension of the Welge-JBN method to three phases and used this method to calculate three-phase relative permeability. Water, benzyl alcohol and decane were the three immiscible liquids which played the role of water, oil and gas in the conventional three-phase system. They found

that the water and gas relative permeabilities depend on their own saturations, respectively, and oil relative permeability depends on the saturation of the three phases. They concluded that Stone's Model I overpredicts the actual benzyl alcohol relative permeability.

Marek et al.[1991] measured three-phase relative permeability of limestones having a bimodal pore-size distribution using the steady-state method. The fluids used were brine (50,000 ppm CaCl_2), oil (50/50 iododecane/hexadecane) and nitrogen which simulated the reservoir fluid system. They did not draw smooth isoperms through their data points, but their calculated isoperms (using a model they developed) are convex towards the oil apex.

The following table summarizes the three-phase relative permeability experiments by various investigators.

Table 2.2: Summary of Three-Phase Relative Permeability Investigations

Author(s)	Porous	Experimental	<u>Shape of Isoperms</u>		
	Media	Method	Oil	Gas	Water
Leverett & Lewis (1941)	Unconsolidated sand	Single core dynamic	Concave	Convex	Linear
Caudle et al. (1951)	Consolidated sandstone	Penn-State	Concave	Convex	Conca.
Corey et al. (1956)	Berea sandstone	Hassler capillary	Concave	Linear	Linear
Reid (1956)	Unconsolidated sand	Single core dynamic	Convex	Concave	Conca.

Table 2.2: Summary of Three-Phase Relative Permeability Investigations..... Cont'd

Author(s)	Porous	Experimental Method	<u>Shape of Isoperms</u>		
	Media		Oil	Gas	Water
Snell (1961)	Unconsolidated sand	Penn-State	Convex	Convex	Conca.
Sarem (1966)	Berea sandstone	Extension of Welge's method	Linear		
Donaldson & Dean (1966)	Berea sandstone & Arbuckle limestone	Extension of Welge's derivation	Concave	Concave & Convex	Conca.
Saraf and Fatt (1967)	Boise sandstone	Dynamic	Convex	Linear	Linear
Schneider & Owens (1970)	Torpedo sandstone	Dynamic			Linear
van Spronsen (1982)	Berea sandstone	Steady-state centrifuge	Concave		Conca.
Saraf et al. (1982)	Fired Berea sandstone	Unsteady- state	Concave	Linear	Linear

Table 2.2: Summary of Three-Phase Relative Permeability Investigations..... Cont'd

Author(s)	Porous	Experimental	<u>Shape of Isoperms</u>		
	Media	Method	Oil	Gas	Water
		displacement & dynamic			
Oak et al. (1988)	Fired Berea sandstone	Penn-State	Concave	Linear	Linear
Grader & O'Meara (1988)	Glass beads	Dynamic	Convex	Concave	Convex
Maini et al. (1989)	Unconsolidated sand	Steady-state	Concave	Linear	Linear
Marek et al. (1991)	Limestone	Steady-state	Convex		

2.5 Correlations for Predicting Three-Phase Relative Permeability

Due to the scarcity of reliable three-phase laboratory data, engineers have relied on theoretical and empirical models which make use of such information as capillary pressure and/or two-phase relative permeabilities to predict three-phase flow behaviour. Several models

have been proposed to fit the observed experimental relative permeability data. These range from simple curve fits to detailed statistical or mechanistic models. At present, the simplest models are the most widely used because of the limited experimental data to justify the use of a more complex model. Some of the more complex models, such as network or percolation theory models, offer the hope of understanding the processes governing the competing flow of fluids in porous media.

The first model (Equation 2.4) of relative permeability in three-phase flow was

$$k_{ro} = \frac{(S_L - S_w)^3}{(1 - S_L)^4} (S_w + S_L - 2S_L) \quad (2.4)$$

published by Corey et al.[1956]. The model was based on the concept of approximating the flow paths through a rock by the equivalent hydraulic radius of a bundle of capillary tubes. A tortuosity correction, developed by Burdine[1953], was included to account for the differences in path length of tubes of different sizes. Corey's model assumed the wetting and non-wetting phase relative permeabilities to be independent of the saturation of the other phases, in agreement with limited experimental data. (This assumption is used in most of the models developed subsequently). The intermediate-wetting phase occupies the flow channels which are intermediate in size between those occupied by water (wetting) and gas (non-wetting). Its flow may be interfered with by both the wetting and the non-wetting fluids. An advantage of Corey's method is that it requires only a single suite of gas/oil relative permeability data (measured at a constant water saturation) to predict gas and oil relative permeabilities for all saturations. However, the model cannot be adjusted to force the end points of the isoperms to correspond to both measured two-phase oil/gas and oil/water relative permeabilities.

Naar and Wygal[1961] extended the two-phase imbibition permeability model of Naar and Henderson[1961] to the case of three-phase imbibition. This model is also based on the concept of flow in straight capillaries, but with the added complications of random interconnections of pores and of storage capacity which makes possible blocking (trapping) of

the non-wetting phase by the invading wetting fluid. Relative permeabilities to the wetting and non-wetting phases are considered to depend on the wetting or non-wetting phase saturations, respectively, while the intermediate-wetting phase relative permeability depends on all three phase saturations. Because of the assumptions made in deriving the Naar/Wygal model, a single parameter (irreducible water saturation) completely characterizes the isoperms. Thus, there is no method for adjusting the curve end point to fit either gas/oil data at an irreducible water saturation or water/oil data at zero gas saturation.

Land[1968] developed an improved model for imbibition relative permeability which takes into account the effect of initial saturations. This model assumes (based on published experimental data) that the maximum residual hydrocarbon saturation is constant, whether the hydrocarbon is gas or oil. Land's model is similar to the model of Naar and Wygal[1961]; however, Land points out that Naar and Wygal erroneously placed the trapped gas saturation in the largest pores rather than the smaller pores more likely to be invaded first by the wetting phase. Land presented the model as a set of integral equations giving the dependence of relative permeability on saturation, saturation history and the relation between saturation and capillary pressure. The model qualitatively predicts the increase in wetting phase relative permeability (at a given saturation) caused by trapping of the non-wetting phase. Because it takes into account the fluid saturation history, it offers the best approach to date to modelling relative permeability with the bundle-of-capillaries model.

Parker et al.[1987] proposed a model for intermediate-wetting phase relative permeability based on a model for two-phase relative permeability developed by Mualem[1976]. The permeability to a particular phase in Mualem's permeability model is assumed to be proportional to the square of the mean hydraulic radius of the pores occupied by that phase. This contrasts to the model of Corey et al.[1956] in which the phase permeability was assumed proportional to the mean hydraulic area, or the mean square hydraulic radius. A comparison of the models with experimental data has been presented by van Genuchten and

Nielsen[1985], showing that Mualem's model is applicable to a wider variety of soils than is the Corey-Burdine model.

The methods most commonly used for the prediction of three-phase relative permeability are those proposed by Stone (Method I[1970] and Method II[1974]). Both are probability-based models, and both assume the relative permeabilities of the wetting and non-wetting phases depend only on the saturation of the wetting and non-wetting phases, respectively. Thus, the model-dependent permeability applies only to the intermediate-wetting (oil) phase.

For the oil phase, Stone's Method I[1970] assumes that the flow of oil is impeded by the presence of gas and water, and that the effects of gas and water are mutually independent. Oil relative permeability is treated as a linear function of the normalized oil saturation, S_o^* , modified by functions β_w and β_g which depend on the water and gas saturations, respectively. Since the effects of the presence of water and gas are assumed to be independent, β_w and β_g can be determined independently. To maintain consistency at the limits of two-phase saturation (oil/water or oil/gas) β_w is chosen to be proportional to the relative permeability to oil in the presence of water at zero gas saturation, and β_g is chosen to be proportional to the relative permeability to oil in the presence of gas at the connate water saturation. The β values include a saturation weighting function $(1/(1-S_i))$, where S_i represents the normalized saturation of water or gas corresponding to β . The base permeability for calculating relative permeability is chosen as k_{ocw} , the permeability to oil at the connate water saturation. Therefore $k_{row} = k_{rog} = 1$ at zero gas saturation and connate water saturation.

$$k_{ro} = S_o^* \frac{k_{row}}{(1-S_w^*)} \frac{k_{rog}}{(1-S_g^*)} = S_o^* \beta_w \beta_g \quad (2.5)$$

Stone suggested that the normalizing factor (the denominator) for S_i be $1 - S_{wc} - S_{om}$, where S_{wc} is the connate water saturation and S_{om} is the irreducible residual oil saturation. He cited experimental evidence indicating S_{om} should be in the range $0.25 \cdot S_{wc}$ to $0.5 \cdot S_{wc}$. The effect of using $S_{om} > 0$ is to force the residual oil saturation to be everywhere greater than or equal to S_{om} . Thus, if a fixed value of S_{om} is used, it should be less than or equal to the smaller of S_{orw} and S_{org} . Use of a fixed S_{om} larger than either of these values will cause a discontinuity in the predicted isoperms at one or both of the two-phase end points, which could lead to difficulty in the use of a reservoir simulator. A non-zero value of S_{om} affects the low-permeability isoperms much more than the higher-permeability isoperms.

Stone's Method II[1974] assumes the total permeability (sum of oil, gas and water permeabilities) is the product of the total water/oil permeability ($k_{row} + k_{rwo}$) measured at zero gas saturation and the total gas/oil permeability ($k_{rog} + k_{rgo}$) measured at irreducible water saturation. Thus

$$k_{ro} + k_{rw} + k_{rg} = (k_{row} + k_{rwo})(k_{rog} + k_{rgo}) \quad (2.6)$$

Gas and water relative permeabilities are assumed to be the same in two-phase and three-phase flow, and can be determined from two-phase data; therefore

$$k_{ro} = (k_{row} + k_{rwo})(k_{rog} + k_{rgo}) - k_{rwo} - k_{rgo} \quad (2.7)$$

In Equation 2.7, the subscripts "go" and "wo" have been retained for k_{rg} and k_{rw} to indicate the expected source of the data. Stone specified the basis for relative permeability calculations for Method II should be the permeability to oil at connate water saturation and zero gas saturation, as for Method I. Inspection of Equations 2.5 and 2.7 shows that if k_{row} and k_{rog} are not unity at the connate water saturation, the equations will not predict the correct two-phase (water/oil and oil/gas) relative permeabilities as the saturation of the third phase approaches zero. Other versions of Stone's methods have been published by Dietrich & Bondor[1976], Aziz & Settari[1979] and Kokal & Maini[1990].

Another interesting model was proposed by Delshad and Pope[1989]; it is independent of the two-phase relative permeability data. The model is described below:

$$k_{ro} = k_{row}^* [\overline{a} \overline{S}_o^* (1 - \overline{S}_w)^{\beta} + (1 - \overline{a}) \overline{S}_o^* (1 - \overline{S}_g)^{\delta}] \quad (2.8)$$

The parameters α , β , γ , δ , and 'a' were defined such that the model at the two-phase limits takes the values of experimental two-phase data. In other words, α and γ are set such that $\gamma = \alpha + \beta = A_{ow}$, $\alpha = \gamma + \delta = A_{og}$, and $a = 1/2$. A_{ow} and A_{og} are the exponents of the fitting equations of two-phase oil/brine and oil/gas relative permeability data.

Alema'n et al.[1984] developed a statistical structural model for prediction of two-phase relative permeability based on a local-volume-average approach to a bundle of capillaries model. In this model, pores are randomly oriented in space, but pore interconnections within the averaging volume are not recognized. The work was extended by Alema'n[1985] to three-phase flow with the derivation of an equation which reduces to Stone's method I if either of the two-phase relative permeabilities to the intermediate-wetting phase is a linear function of saturation.

Three-phase studies involve a lot of problems in experimental control. Donaldson and Kayser[1981] have categorized the reasons for such a divergence in experimental three-phase relative permeability data as follows: a) errors introduced in saturation measurements in various experimental methods; b) errors introduced due to the neglect of capillary end effects and saturation hysteresis phenomena; c) variation caused by the use of different oils, brines and cores which could exhibit different wettability characteristics; d) assumptions made to facilitate experimental procedures or calculations; e) inadequacy of the mathematical formulation to represent three-phase flow conditions.

The accuracy of reported results has undoubtedly improved with improvements in technology over a period spanning half a century. The number of reported experimental studies

is relatively small and a good case can be made for continuing this type of work in different systems. However, the measurement techniques remain tedious and not well suited for making measurements in reservoir cores under reservoir conditions. The effort required in completely characterizing relative permeability behaviour of a single core is so great that measuring three-phase relative permeabilities on a routine basis is not practical. Therefore, reservoir simulation studies will have to rely on prediction techniques for some time to come. The immediate objective of research in this area should be to improve the reliability of prediction techniques. Unfortunately, this can not be achieved until many more three-phase relative permeability measurements in different types of system become available.

3. STATEMENT OF THE PROBLEM AND OBJECTIVES

Two major observations can be made from the preceding discussion. First, it is evident from the literature that relative permeability is one of the more important properties of a rock-fluid system, and is necessary for describing and understanding the mechanisms of fluid flow in porous media. This emphasizes the importance of determination of three-phase relative permeability experimentally.

Although a large number of studies pertaining to two-phase relative permeability have been reported in the literature, only a few studies involve three-phase flow through porous media. A recent review of three-phase relative permeability shows that there are fewer than 20 reported experimental studies on three-phase flow through porous media. Only 8 data sets out of these 20 were complete enough for evaluating the goodness-of-fit of various estimation techniques[Baker, 1988]. The effect of different variables such as, wettability, viscosity, temperature, and so forth on three-phase relative permeability has not been determined. Therefore, experimental investigation of three-phase relative permeability is required to ascertain the effect of the variables mentioned above.

The second observation is that, over the past 25 years, a number of studies have reported temperature effects on two-phase relative permeabilities in porous media. Several of these[Maini and Batycky, 1985; Maini and Okazawa, 1987; Maini and Coskuner, 1988; Torabzadeh and Handy, 1984; Quettier and Corre, 1986; Bennion et al., 1985] report a significant effect of temperature on oil/water relative permeability. Similarly, some effects can be expected in two-phase oil/gas relative permeabilities. Therefore, it is probable that three-phase relative permeabilities would also be temperature sensitive. Thermal methods for the recovery of heavy oil, such as steam injection and in-situ combustion, involve the simultaneous flow of oil, water and gas at high temperatures. Therefore, a knowledge of three-phase relative permeability at elevated temperatures is required for these systems. Moreover, whether or not

the three-phase relative permeabilities are temperature sensitive for a given system can be determined only by experimental evaluations.

The primary goal of this study is to develop a system which is capable of measuring three-phase relative permeability at high temperatures and high pressures. Another objective is to measure reliable three-phase relative permeabilities at high temperatures and high pressures in a clean rock-fluid system. When sufficient experimental data have been gathered, two other goals can be achieved. First, the experimental data can be used for evaluating the accuracy of various correlations in matching the measured three-phase relative permeability at elevated temperatures. Second, with the help of the experimental data at different temperatures, the effect of temperature on three-phase relative permeability can be determined.

Needless to say, to achieve the above goals, one must have reliable and accurate three-phase relative permeability data. Therefore, a reliable measurement technique has to be selected on the basis of least disadvantages. The review of the literature on three-phase relative permeability showed that three types of measurement techniques have been used in the past: (1) the steady-state method, (2) the unsteady-state method, and (3) the centrifuge method. The steady-state technique is considered to be the most reliable [Maini et al., 1989]. Also, the steady-state technique allows better control of saturation history and minimizes the instability phenomena. Therefore, this investigation will use this method only.

In order to estimate relative permeabilities by the steady-state method, the following steps were taken:

- a. Establish steady flow of three fluids at constant temperatures throughout the porous medium.
- b. Measure pressure drop and flow rate of each fluid.
- c. Having obtained all the measurable quantities, one can use Equation 2.3 for the flow of each phase - oil, water and gas, to estimate directly the relative permeabilities.

4. EXPERIMENTAL EQUIPMENT, MATERIALS AND PROCEDURE

4.1 Equipment

The experimental apparatus was designed to perform two and three-phase corefloods at isothermal conditions up to about 150°C. A schematic diagram of the equipment used is shown in Figure 4.1.

4.2 Core Holder

The success of experiments involving fluid flow through porous media often depends on the design of a suitable core holder for maintaining the porous medium under the desired conditions of confining stresses. For measurements related to thermal recovery of heavy oils, it is often necessary to simulate in-situ conditions of triaxial stresses at elevated temperatures. In addition to high temperature and pressure, the core holder should be capable of withstanding corrosive fluids. It is desirable that the dead volume in the end fittings be kept to a minimum. The core holder should also ensure that bend and other deformations in the shape of the core are minimized. If a sleeve is used for applying the confining pressure, it should be pliable enough to provide a tight seal between it and the sand.

A core holder design which fulfils these requirements is shown schematically in Figure 4.2. It has been used extensively at the Petroleum Recovery Institute in Calgary at temperatures up to 275°C and confining pressures up to 30 MPa over extended periods of time. The core holder consists of a thick-walled, stainless steel tube to which two end caps have been attached with cap screws. The sand is contained inside a pliable lead sleeve which is flared at one end to form a gasket between the inlet end cap and the cylindrical body. The other end of the sleeve is attached to a floating piston and a cylindrical stem which together serve as the production head. The stem protrudes out of the other end cap through an O-ring seal. The piston can be moved axially by tightening two large screws for applying axial stress

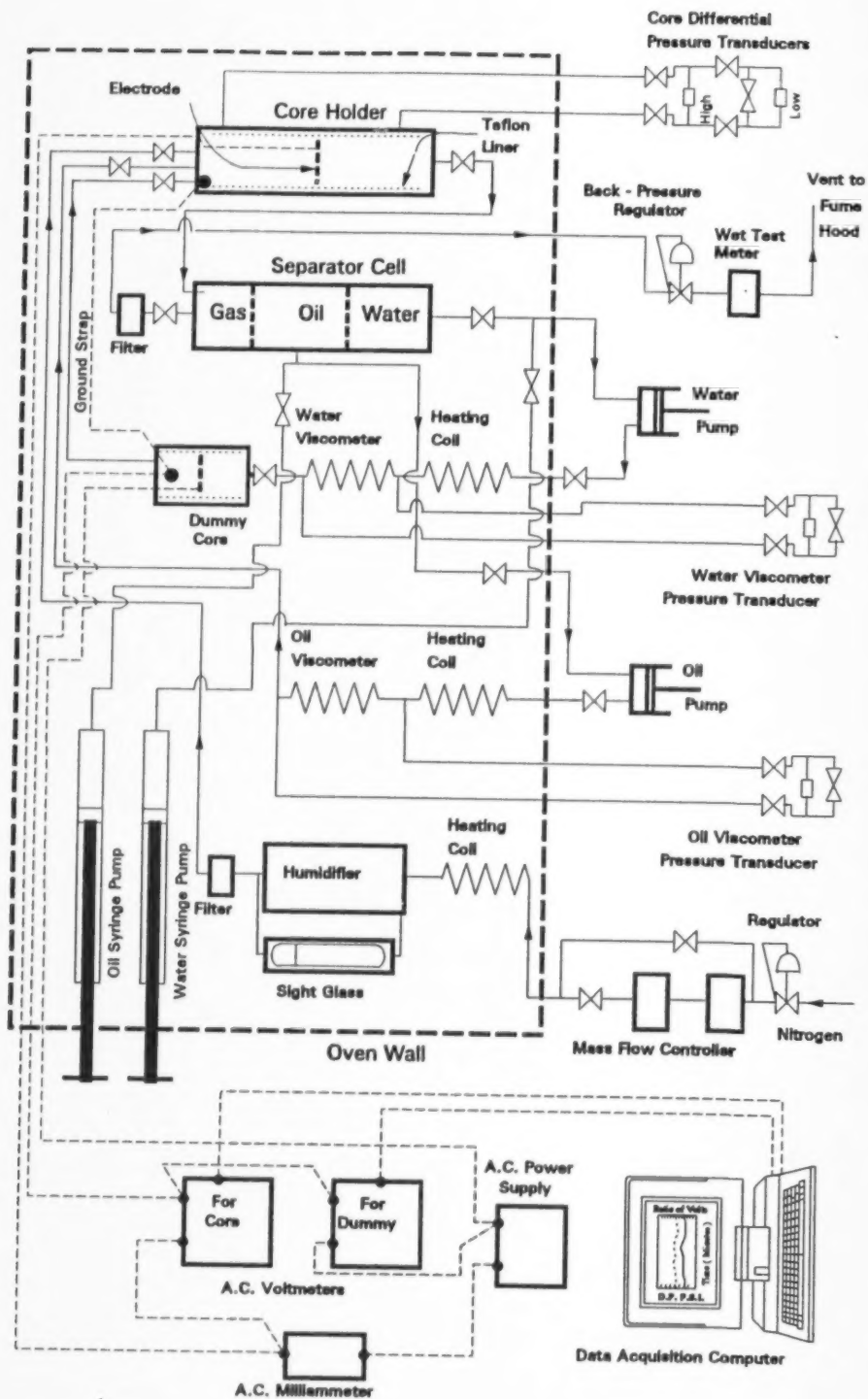


Figure 4.1: Schematic Diagram of the Experimental Apparatus

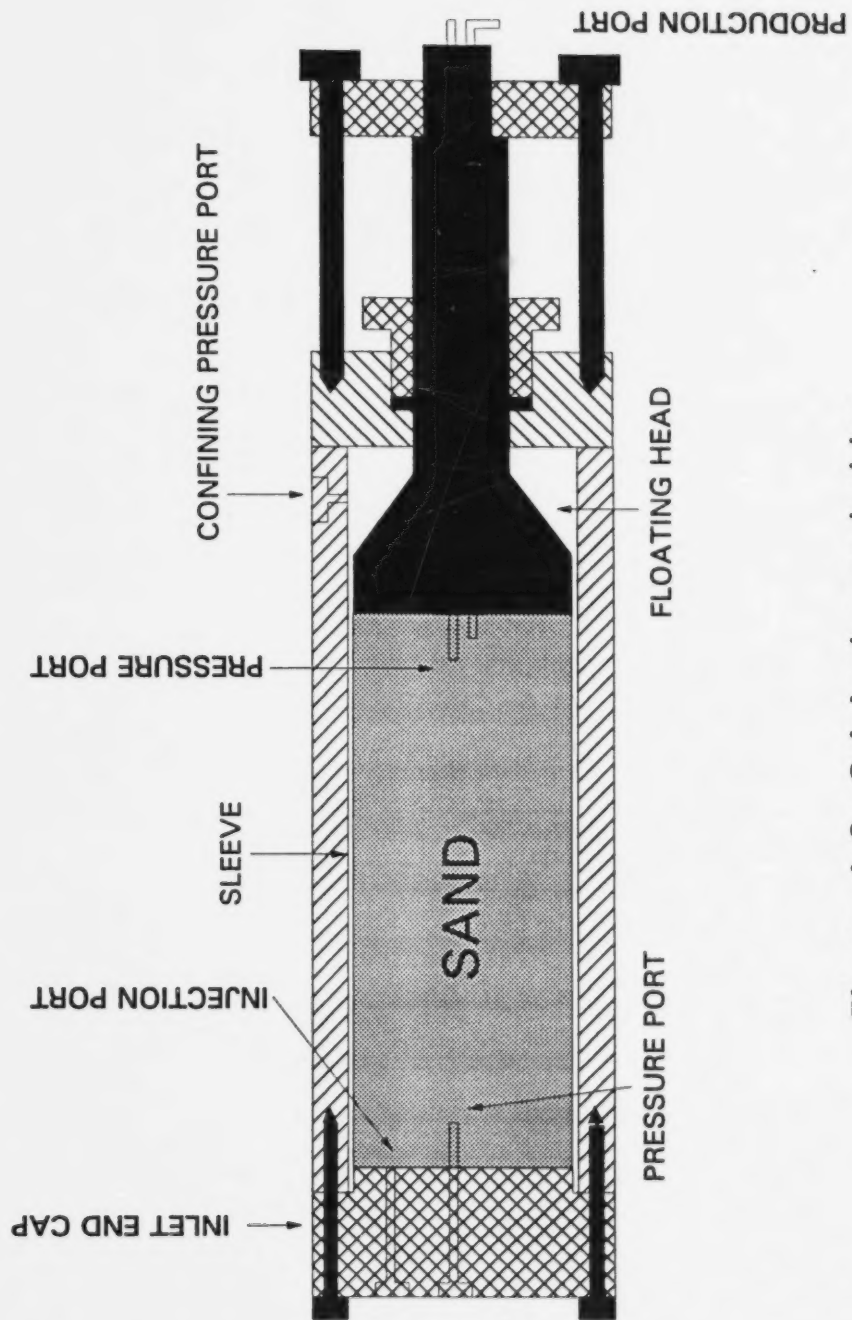


Figure 4.2: Original core holder

on the sand. The radial confining pressure is applied hydrostatically through the confining pressure port. This port has been intentionally placed away from the lead sleeve to avoid damage to the sleeve in case of an accidental loss of confining pressure. For the same reason, the clearance between the lead sleeve and the core-holder body has been reduced to less than 1 mm. This small clearance also prevents bending and large deformations of the shape of the core.

Both the injection end cap and the floating production head contain built-in fluid distribution patterns. These consist of shallow circular and radial grooves milled into the face in contact with the sand. These grooves are covered with a fine stainless steel wire mesh which prevents the sand from migrating into the tubing. Separate ports are provided for fluid flow and pressure measurement.

4.3 Experimental Set-Up

Figure 4.1 shows a detailed schematic diagram of the apparatus. Except for the pump assemblies, syringe pumps, the whole experimental setup was placed in a constant temperature cabinet with an average deviation of 0.5°C from the set point. Oil and brine were flowed in a closed loop system to maintain the material balance. The brine flow started from the bottom of the windowed separator cell and passed successively through the flow pump, the heat exchanger coil, the reference cell, the viscometer tube and the core assembly before returning to the separator cell. Therefore, any change in the volume of brine inside the core was accompanied by an equal change in the volume of brine in the separator cell. Similarly, the oil flowed from the middle of the separator cell and passed through the oil pump (Beckman Model 100A), the heat exchanger tube, the oil viscometer tube and the core before returning to the separator cell. To maintain the required volumes of the liquids in the separator cell, two syringe pumps, one each for oil and brine, were connected to the windowed separator cell as shown in Figure 4.1.

Gas was flowed in an open loop manner. The gas was taken from a commercial gas cylinder, flowed through a mass flow controller, a fixed bed humidifier to saturate it with water, a mist filter, the test core assembly, the separator cell, a second mist filter and out through a back pressure regulator. The back pressure regulator was used to maintain the necessary amount of pressure on the whole system.

Two differential pressure transducers were placed in parallel to measure the pressure drop across the core. One was of higher range (0 - 345 kPa) and the other was of lower range (0 - 69 kPa). Pressure drops across the two capillary viscometers were also monitored and recorded continuously. Only the differential pressure across the core was actually used to calculate the relative permeabilities. Other pressure data, such as the differential pressures across the capillary tubes, were used to check the performance of the pumps.

4.4 Modifications of the Apparatus

During the course of the experiments, it became apparent that the reliability of the measurements was affected by several factors. One of the major problems in the steady-state method is the capillary effects at the outflow end of the core. Secondly, some brine was lost from the system with the gas stream being purged out of the system. This occurred despite full humidification of the gas stream before entering the core. The reason was related to the small expansion of the gas phase passing through the core. This brine loss reduced the reliability of the material balance based saturation measurements. Thirdly, despite filling the transducer lines with the wetting phase, oil and gas always entered these lines. Therefore, a major improvement of the equipment was undertaken with the following objectives:

1. Minimize the capillary end effects.
2. Improve the reliability of saturation measurements.
3. Improve the reliability of the differential pressure measurements.

4.4.1 Minimization of Capillary End Effects

In this work, the technique proposed by Richardson and Perkins[1957] was used to minimize the capillary end-effect. The final design of the core holder is shown schematically in Figure 4.3. The cross sectional area of the narrow tube was more than two orders of magnitude smaller than that of the main core. The length of the narrow section was 12.7 cm while that of the main core section was 40.7 cm. A short length narrow section was used to minimize the effect of saturation variation in this section on the core average saturation measurements which were determined by material balance. The pore volume contained in this section was less than 0.3% of the pore volume in the main core section. Therefore, the effect of any saturation variation in the narrow section on core average saturation can be neglected.

An experimental evaluation of the effect of attaching an end-effect absorbing narrow tube was undertaken to see whether the end effects were reduced or not. Two-phase oil/water imbibition relative permeability experiments were conducted at 75°C with two cores. The first core was without the end-effect absorbing section (Figure 4.2) and the second one had the narrow tube attachment at the outflow end (see Figure 4.3). The results of those tests are shown in Figure 4.4. The water relative permeability was not affected by the presence of the end-effect absorbing section. However, the oil relative permeability shows some effect. Tabular data are given in Table F.1 in Appendix F. At both end points, the two oil relative permeability curves come together; but in the mid-portion of the curves, the two oil relative permeabilities at the same water saturation are different. The oil relative permeabilities are higher in the core equipped with the end-effect absorbing section. This is expected, because the additional end-effect pressure drop shifts the relative permeability curve downward[Sandberg et al., 1958]. At irreducible water saturation, only oil is flowing through the porous medium, and because it is the nonwetting phase, it does not build up at the outlet end of the sandpack and consequently there is no end-effect. On the other hand, as the residual oil saturation is approached, capillary pressure gradients become negligible[Richardson and Perkins, 1957].

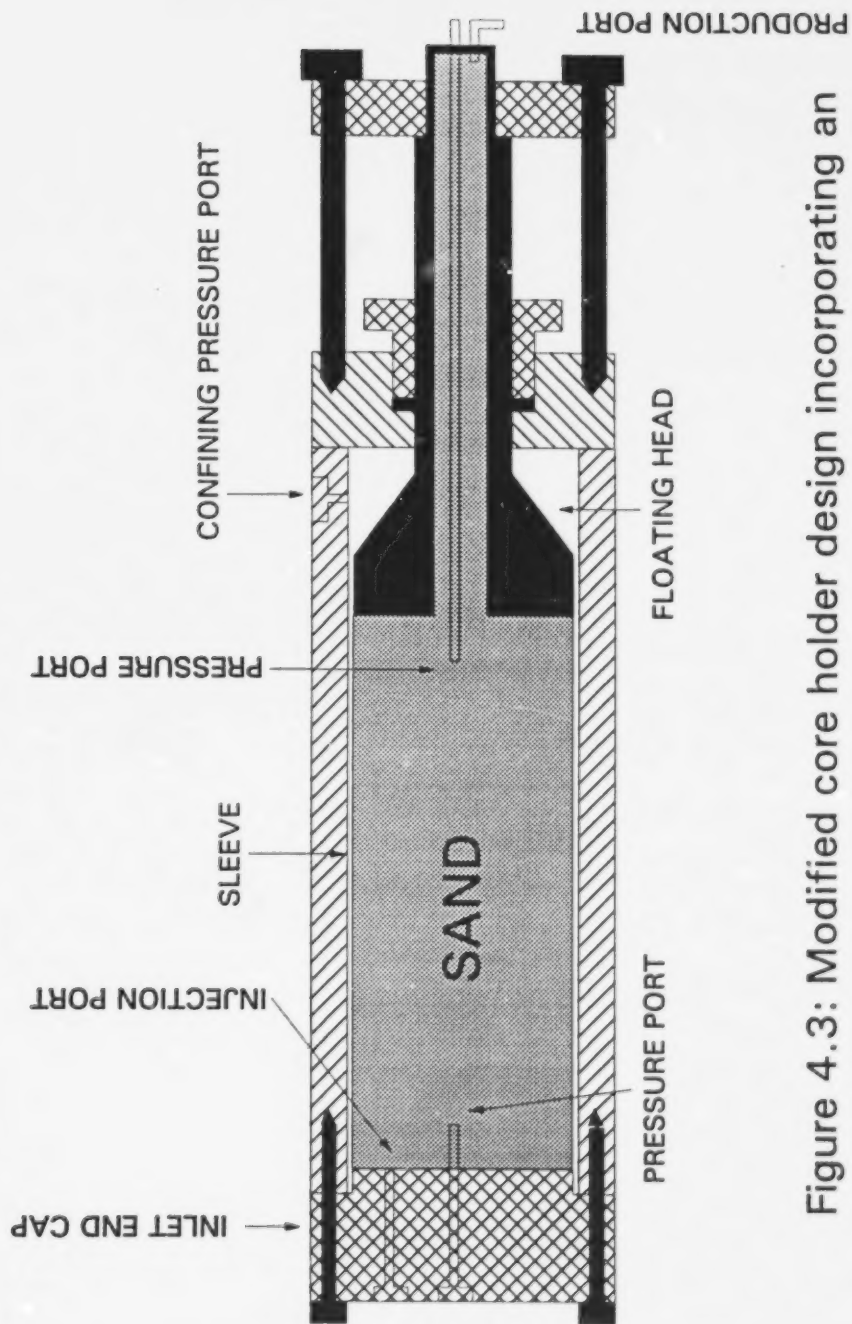


Figure 4.3: Modified core holder design incorporating an end-effect absorbing section

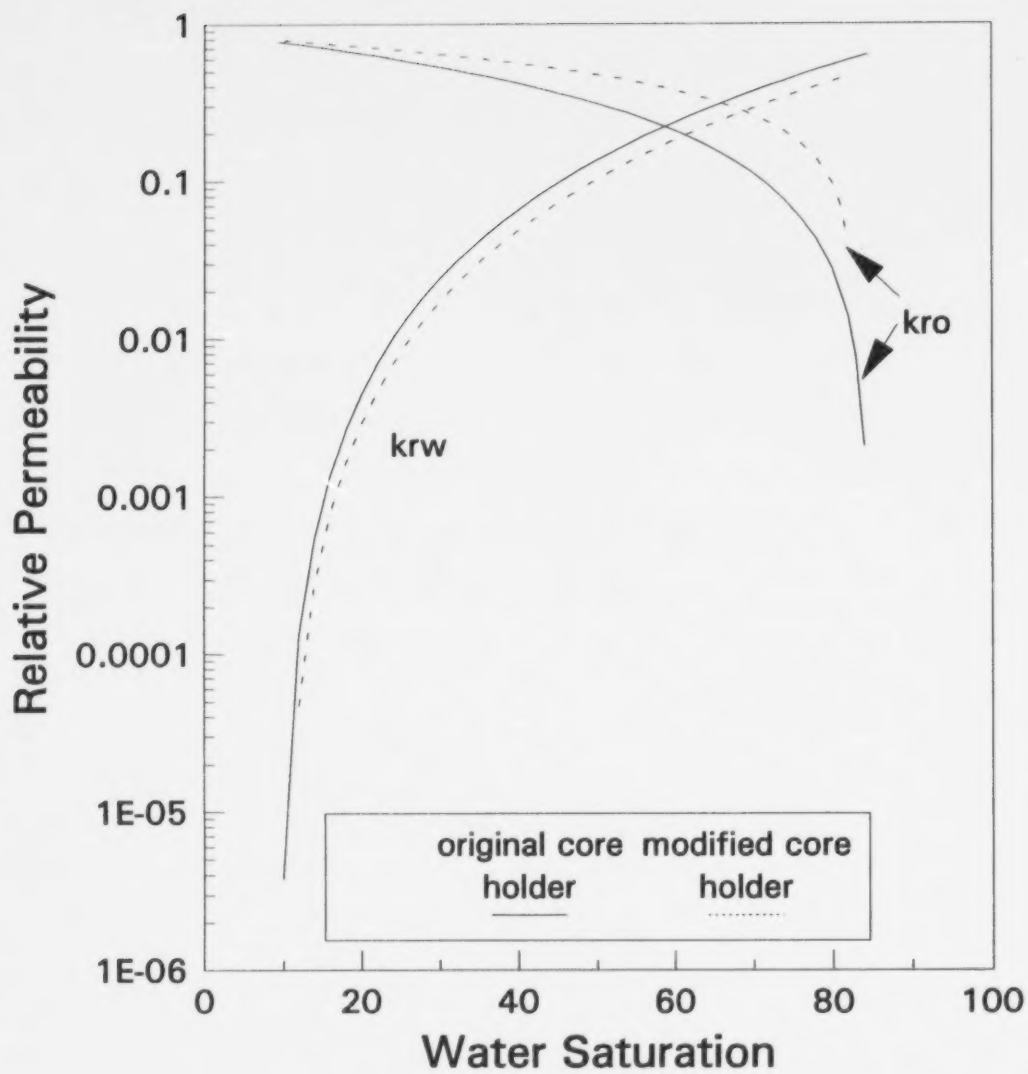


Figure 4.4: Experimental Evaluation of the End-Effect Absorbing Section

The results show that the narrow outflow section had a significant effect on measured oil relative permeabilities. Although, these tests do not prove that the end effects were totally eliminated, the presence of very high flow velocity near the outflow end is expected to have had a positive effect.

4.4.2 In-Situ Brine Saturation Measurement

As mentioned previously, to overcome the problem of water loss, it was necessary to find an alternative way of saturation determination or to eliminate the problem. The only sure way of preventing the brine loss appeared to be to find some means of re-circulating the gas phase and thus eliminating the out going gas stream. While it is possible to design a gas re-circulation system based on recompressing the gas, it adds another complication- some brine is likely to drop out of the gas as a result of the recompression. Because such a recompression unit would have to be located outside the oven, the unavoidable cooling of the gas stream would also cause brine condensation problems. Therefore, another alternative was sought.

From previous experiments, it was observed that material balance and saturation measurements were much more reliable for the oil phase. Therefore, it would be necessary only to find an alternate method of measuring the brine saturation. An in-situ technique based on electrical resistivity measurement was adopted because of its simplicity and relatively low cost. Other alternatives, such as micro-wave and X-ray attenuation methods, were ruled out due to the large capital expense required and the difficulties in using those techniques at high temperature.

Figure 4.5 shows the placement of electrodes within the core holder. A coarse monel screen, placed perpendicular to the core axis near the centre of the core was used as one of the electrodes. The body of the core holder served as the other electrode. A teflon inner sleeve was placed between the sand and the lead sleeve to electrically isolate the sand. Thus, the electrical current had to flow between the monel screen and the end plates of the core holder

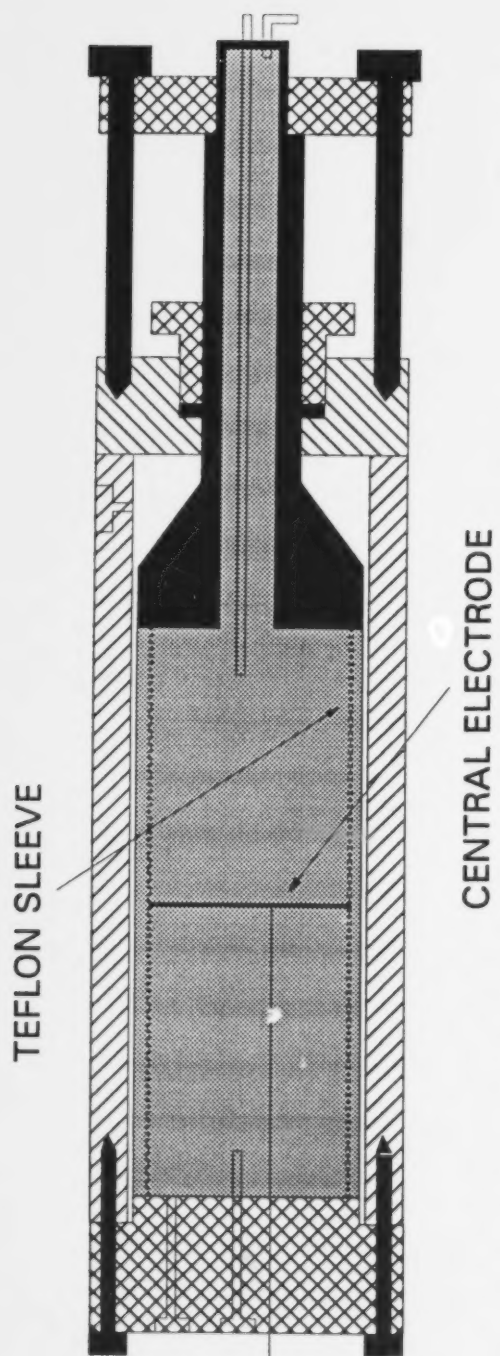


Figure 4.5: Schematic diagram showing the placement of a central electrode and the teflon sleeve

through the sand. The resistivity measurement was carried out at 1000 Hz. To eliminate the effect of brine composition, the resistivity of the core was compared with the resistivity of another sand pack placed in the brine re-circulation system. This second pack remained fully saturated with brine at all times and because it was part of the brine re-circulation path, it contained the same brine as that flowing through the core.

A calibration curve, relating the electrical resistivity index of the core to its brine saturation, was established by carrying out two-phase oil/brine and gas/brine tests (see Figure 4.6). The resistivity index was measured directly by measuring the ratio of the electrical resistance of the core and the resistance of the fully brine saturated secondary cell. The brine saturation in the oil/brine tests was determined by material balance. In the case of the brine/gas tests, the brine saturation was determined by measuring the volume of additional brine needed to completely re-saturate the core following a blow-down to atmospheric pressure.

4.4.3 Differential Pressure Measurement

The last difficult problem was the error in the measurement of pressure drop across the core. The reason was some of the oil (and sometimes gas) always entered the pressure transducer tubes, no matter how thoroughly they were cleaned, before the start of the experiment. The problem was eliminated in two stages. First, water-wet pressure taps were used to measure the pressure drop. But, the problem was still there and other options were sought. In the second stage, the differential pressure transducer was placed in a gravity stable position. In the previous work [Maini, et al., 1989], the transducer assembly was placed in a horizontal position level with the top of the core. In the final version of the experimental set-up (Figure 4.1), the transducer assembly was placed at the base of the oven with the lines going vertically upwards. This eliminated the problem, because oil (and gas) being lighter than water cannot flow down the lines.

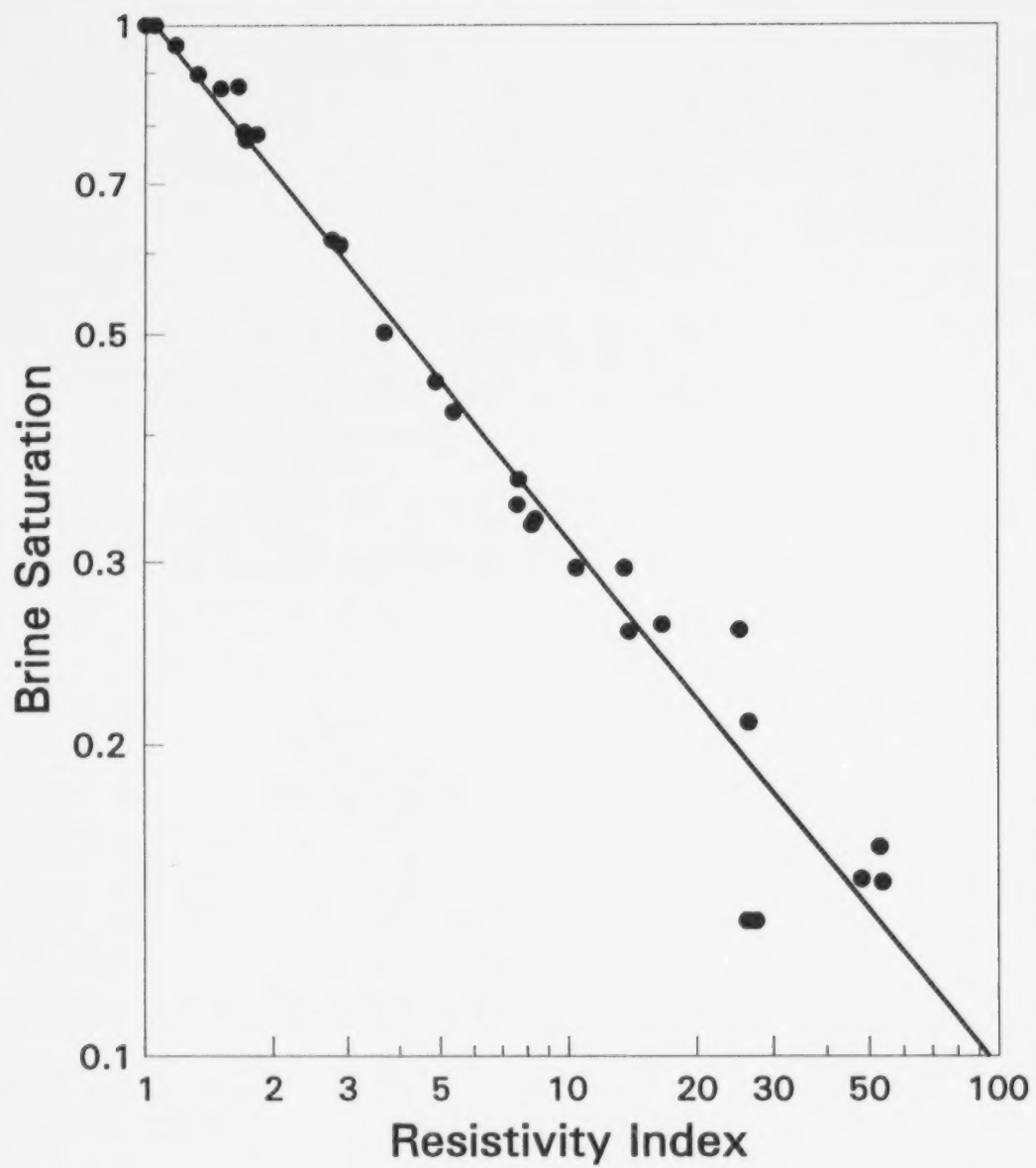


Figure 4.6: Brine Saturation Calibration Curve

4.5 Materials

In all of the runs, the core was packed with clean unconsolidated Ottawa sand. The fluids used were 1% brine (NaCl) solution, Vitrea 150 mineral oil and commercial nitrogen gas. The properties are given in Table 4.1. Vitrea 150 is a highly viscous non-paraffinic mineral oil which was supplied by Shell Oil Co.

4.6 Absolute Permeability Measurements

A dry, clean Ottawa sand core was packed and confined by triaxial stress. The core was then evacuated before a 1% brine solution was imbibed into the core. The brine was imbibed vertically upwards. Then the brine was flowed downwards at a rate of 10 cc/min. When the pressure drop across the core stabilized, readings were taken for the calculation of the absolute permeability. The same procedure was followed for the calculation of the absolute permeability at test temperatures.

4.7 Oil Flood

Vitrea 150, a mineral oil, was injected at the top into the brine saturated core at a rate of 5 cc/min. The oil displaced the brine from the core until the brine saturation was reduced to the irreducible saturation and the pressure drop was stabilized for up to 2 hours. The end-point effective permeability was then calculated from this stabilized pressure drop.

4.8 Two-Phase Steady-State Measurements

Before the start of any three-phase experiment, two sets of two-phase steady-state experiments at each temperature were carried out. One was an oil/brine steady-state test and the other was an oil/gas experiment.

In the oil/brine experiments, the fractional flow of oil was reduced from one to zero and that of brine was increased from zero to one. All the experiments were done in an imbibition

Table 4.1: Properties of the sand pack and fluids

Type of sand	140-200 mesh silica sand
Core length	40.7 cm (0.407 m)
Cross-sectional area	25 cm ² (0.0025 m ²)
Pore volume	397.5 ml (0.0003975 m ³)
Porosity	37.8%
Absolute permeability to brine	3.37 darcy
Confining pressure	13.8 MPa
Pore pressure	3.45 MPa
Viscosity of oil (20°C)	450 mPa.s
Viscosity of N ₂ (20°C)	0.02 mPa.s
Viscosity of 1% brine (20°C)	1.03 mPa.s

mode. At each fractional flow, when the pressure drop stabilized, steady-state was assumed. The respective two-phase relative permeability was determined by Darcy's equation.

In the case of the oil/gas two-phase experiment, the brine saturated core was initially oil flooded. Then steady flow of oil and gas was established. The sequence was from low gas/high oil flowrates to high gas/low oil flowrates. At each flow condition, the stabilized pressure drop was used for the determination of the relative permeabilities.

4.9 Experimental Procedure

At the beginning of each run, the core was cleaned with acetone and methylene chloride, and dried with hot nitrogen. The core was then evacuated and filled with a metered volume of brine to determine its pore volume and porosity. The brine loop was completely filled with brine, except for the brine syringe pump and the separator cell which were only partially filled. The oil syringe pump was filled with Vitrea 150 mineral oil and most of the separator cell also contained oil (except for a small volume of brine at the bottom and a gas cap at the top). Nitrogen was then injected to pressurize the system. The absolute permeability of the sand pack was measured by flowing brine vertically downward through it. This process also allowed the brine to become saturated with the gas by flowing through a gas cap in the separator cell. The oil was equilibrated with the gas by circulating it through the same gas cap (in the separator cell) without going through the core. After both fluids became saturated with nitrogen gas, the levels of both liquids in the separator cell and the volumes contained in the syringe pumps were recorded.

Then the core was oil flooded to reduce it to its irreducible brine saturation. The amount of brine produced was monitored by reading the brine level in the separator cell and removing brine into the syringe pump to maintain the level. The oil flow was continued until brine ceased to flow out of the sand pack and the pressure drop across the core stabilized.

The next step was simultaneous injection of brine, oil and gas into the core at different

fluid flow ratios. Each ratio was preset in the direction of increasing gas and brine ratios and decreasing oil ratios to simulate the reservoir behaviour during primary oil production. Each set of flow ratios required approximately 12 hours to reach steady-state equilibrium (as indicated by constant pressure drop and constant fluid levels in the separator). After reaching steady-state, the pressure drop across the core, the resistivity values and the liquid levels in the cell were recorded. Usually, 24 hours were enough for ensuring steady-state conditions at each flow rate setting. However, at zero oil flow, two to three days were needed, depending on the flow of brine and gas. Seven to nine preset flow rate settings were used to reach the flood out condition. The sand pack was isolated and depressurized after residual oil saturation was reached. With the depressurization of the core, liquids were produced with the gas. The liquids were collected in a covered container. The core was extracted by flowing methylene chloride and acetone through it. About ten pore volumes of the solvents were flowed through the sand pack. The core was dried by flowing nitrogen through it at a rate of 50 standard cc/min for about two hours. After that the core was ready for the next run. The produced liquids were distilled overnight to separate the brine and the oil. In this way, the oil and brine saturations were determined at the end of the test.

The relative permeability to each phase was calculated by applying Darcy's law. The maximum error in residual oil saturation measurements was estimated to be $\pm 2.5\%$. The average error in the core average saturation measurement would be considerably less than this value.

4.10 Three-Phase Steady-State Measurements

In the three-phase experiments, after oil flooding of the core, oil, brine and nitrogen gas were flowed simultaneously downward through the core. All the experiments were conducted in the imbibition mode. The flowrates of brine and nitrogen were increased gradually and that of oil was decreased. Six different flowrate ratios were selected so as to cover the saturation

ternary diagram as completely as possible. The ratios were from high gas/low brine to low gas/high brine flowrate.

4.11 Sampling and Analysis

At the end of the experiments, the core was isolated. Then the core was depressurized and extracted with hot acetone and methylene chloride. The recovered liquid mixture was distilled overnight to separate the oil and brine. The residual oil saturation at the end of the experiment was calculated from the total amount of oil recovered from the core.

4.12 Sand Pack and Fluid Properties

The relative permeability experiments in this study utilized unconsolidated sand, brine, nitrogen gas and heavy oil. The physical properties of the brine were taken from steam tables, they were calculated from analytical expressions for nitrogen, and those of sand and oil were determined experimentally.

4.12.1 Viscosity of Nitrogen

The viscosity of nitrogen gas was estimated using the Sutherland equation which was obtained from the International Critical Tables (V-2):

$$\mu_{N_2} = 0.01765 \left[\frac{296.1 + 110.6}{T + 110.6} \left(\frac{T}{296.1} \right)^{3/2} \right] \quad (4.1)$$

where μ is the viscosity (specified in centipoise) and T is the temperature (specified in degrees Kelvin). The nitrogen viscosity is not strongly pressure dependent for the range of conditions encountered in this study.

4.12.2 Ottawa Sand Pack Properties

All the cores were packed with 140-200 mesh silica sand. The porosity and absolute

permeability of the cores were measured at experimental conditions. The packing procedure was found to be reliable on the basis of the reproducible results obtained for cores packed under similar situations.

4.12.2.1 Porosity

After applying the confining pressure, the pore volume of the core was determined and the porosity calculated therefrom. The detailed results are given in Appendix A. The porosity values ranged from 35.9 to 39.4%, with an average value of $38.2 \pm 1.0\%$. There were two reasons for this variation in porosity. First, during the course of the experiments, the core was packed several times. Due to the differences in packing, no two sand packs will yield the same porosity. Secondly, because of the measurements errors, which are inherent in this type of work, different porosity values were obtained.

4.12.2.2 Absolute Permeability

The absolute permeability to brine of each core was determined at the test temperature before the start of an oil flood. The detailed experimental results are presented in Appendix A. The absolute permeability varied from 2.49 to 3.82 darcies. The variation in the absolute permeability was attributed to the change in the compaction of the sand inside the core holder over the period of the experimental runs. Also, due to the measurement errors, the absolute permeabilities are different.

4.12.2.3 Effect of Temperature on Absolute Permeability and Porosity

Table 4.2 presents the average core properties calculated from the experimental results. A statistical analysis showed that the absolute permeabilities and porosities of the cores were not significantly different (see Appendix B). The average value, standard deviation and number of experiments are indicated for each temperature.

To assess the significance of the effect of temperature on absolute permeability and porosity, a statistical Student's t-test was conducted. This test was performed to determine if the variation between populations was greater than the variation due to random error within a population. A calculated t-value greater than the tabulated t^* -value would indicate a significant statistical difference between these populations (see Appendix B).

The relevant parameters for 95% confidence limits are shown in Table 4.3. The results of the t-test showed that the mean absolute permeability and the mean porosity at each temperature were not significantly different from one another.

4.12.3 Heavy Oil Properties

The viscosity of Vitrea 150 was measured at different temperatures. All the measurements were carried out at atmospheric pressure. The viscosity at temperatures other than the measured ones were found using the correlation of Singh et al.[1990]. A C program is given in Appendix C to perform the required calculations. The average values of viscosity are reported in Table 4.4 as a function of temperature, with the detailed viscosity values presented in Appendix D.

The oil density (Vitrea 150) was determined at different temperatures, covering the entire range of the experimental conditions. It was supplied by Shell at 15°C. The data were correlated by linear regression (see Table 4.5 and Figure 4.7).

Table 4.2 : Average Core Properties

Temp. (°C)	Number of Runs	Porosity (%)		Absolute Permeability (darcy)	
		Avg. Val.	Std. Dev.	Avg. Value	Std. Dev.
75	8	38.2	0.96	3.44	0.387
125	8	37.7	1.15	3.29	0.478

Table 4.3 : Statistical Parameters for Temperature

Dependence of Absolute Permeability and Porosity

Temperature (°C)	Number of Runs	Average Absolute Permeability, k (darcy)	Average Porosity, ϕ (%)	95% Confidence Interval	t-value k (ϕ)
75	8	3.44	38.2	± 2.14	0.641
125	8	3.29	37.7	± 2.14	(0.812)

Table 4.4 : Viscosity of Vitrea 150

Temperature (°C)	Viscosity (mPa.s)
20.0	446.5
40.0	126.5
59.0	47.10
75.0	26.55
81.0	25.66
99.8	14.02
139.4	6.03

Table 4.5 : Density of Vitrea 150

Temperature (°C)	Density (kg/m ³)
15.0	875.7
20.0	877.0
40.0	861.3
50.0	857.2
60.0	853.8
80.0	838.9
100.0	828.0
125.0	814.5

Linear regression correlation:

$$\rho_o = 886.066 - 0.57577 \cdot T \quad (r^2 = 0.995)$$

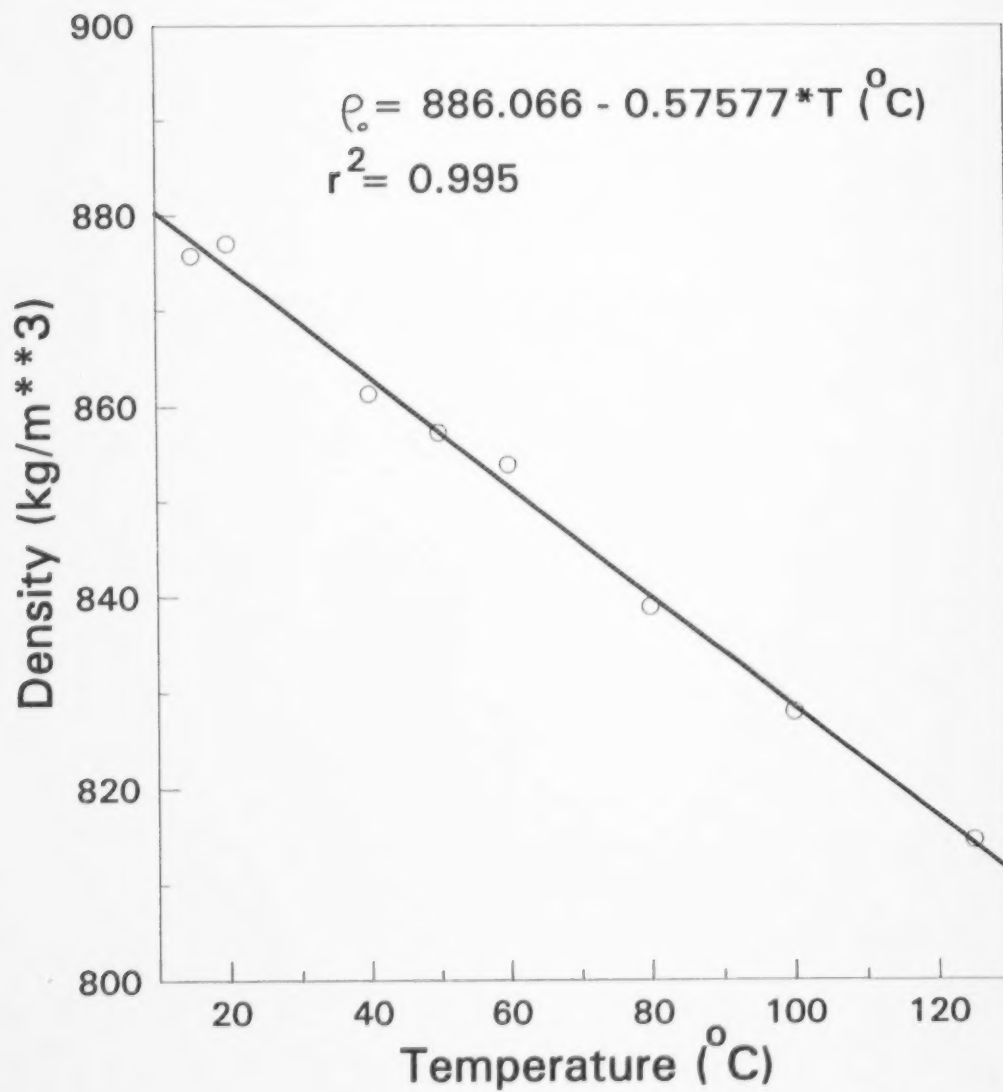


Figure 4.7 :Density of Vitrea 150

5. RESULTS AND DISCUSSION

5.1 Introduction

The purpose of this study was to develop an apparatus which is capable of operating at high temperatures and high pressures for a prolonged period of time and to examine the effect of temperature on three-phase brine-oil-gas relative permeability relations in unconsolidated Ottawa sands. The limited experimental results obtained cannot answer all the questions, as many more experiments involving other parameters, such as fluid properties, are needed to comprehend fully any problem involving three-phase flow. The following results and discussion are intended to explain the observed phenomena in terms of the fundamental properties and to indicate the range of applicability of the measured curves.

5.2 Two-Phase Relative Permeability Experiments

At the start of the three-phase experiments at each temperature, two sets of two-phase relative permeability experiments were performed to define the boundary of the three-phase region. Two-phase oil/brine experiments were performed at zero gas saturation. On the other hand, two-phase oil-gas experiments were performed at the irreducible brine saturation.

5.2.1 Oil/Brine Experiments

Two-phase oil/brine imbibition relative permeability experiments were conducted at each of the temperatures. These experiments were done at zero gas saturation. The end-point oil and brine relative permeabilities along with the irreducible brine and residual oil saturation are given in Table 5.1. The experimental data points are shown in Figures 5.1 and 5.2.

5.2.2 Oil/Gas Experiments

Two-phase oil/gas drainage relative permeability experiments were conducted at each of the temperatures. These experiments were done at the irreducible brine saturation. The end-

Table 5.1 : End-Point Oil/Brine Relative Permeabilities and Saturations

Parameters	T = 75°C	T = 125°C
k_{row}^*	0.786	0.82
k_{rwo}^*	0.593	0.527
S_{wi}	0.1	0.15
S_{or}	0.15	0.18

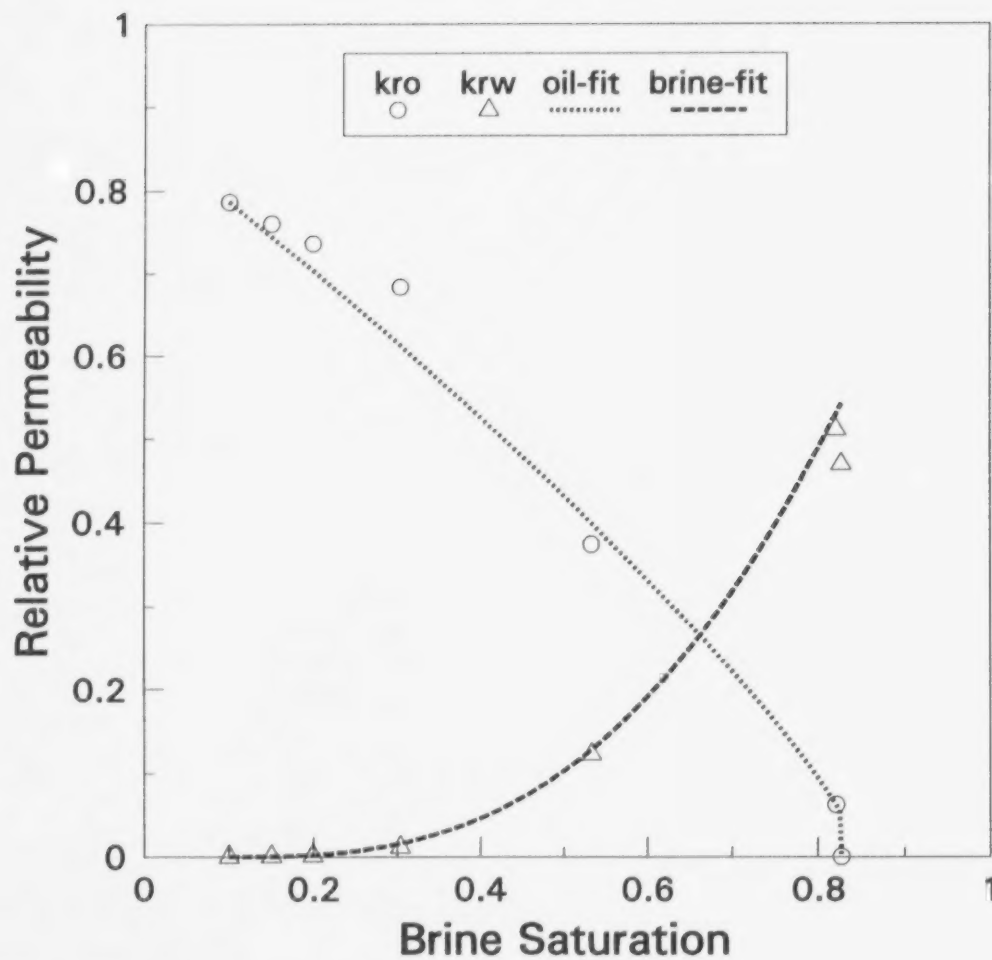


Figure 5.1 :Brine/Oil Two-Phase Relative Permeability at 75 °C

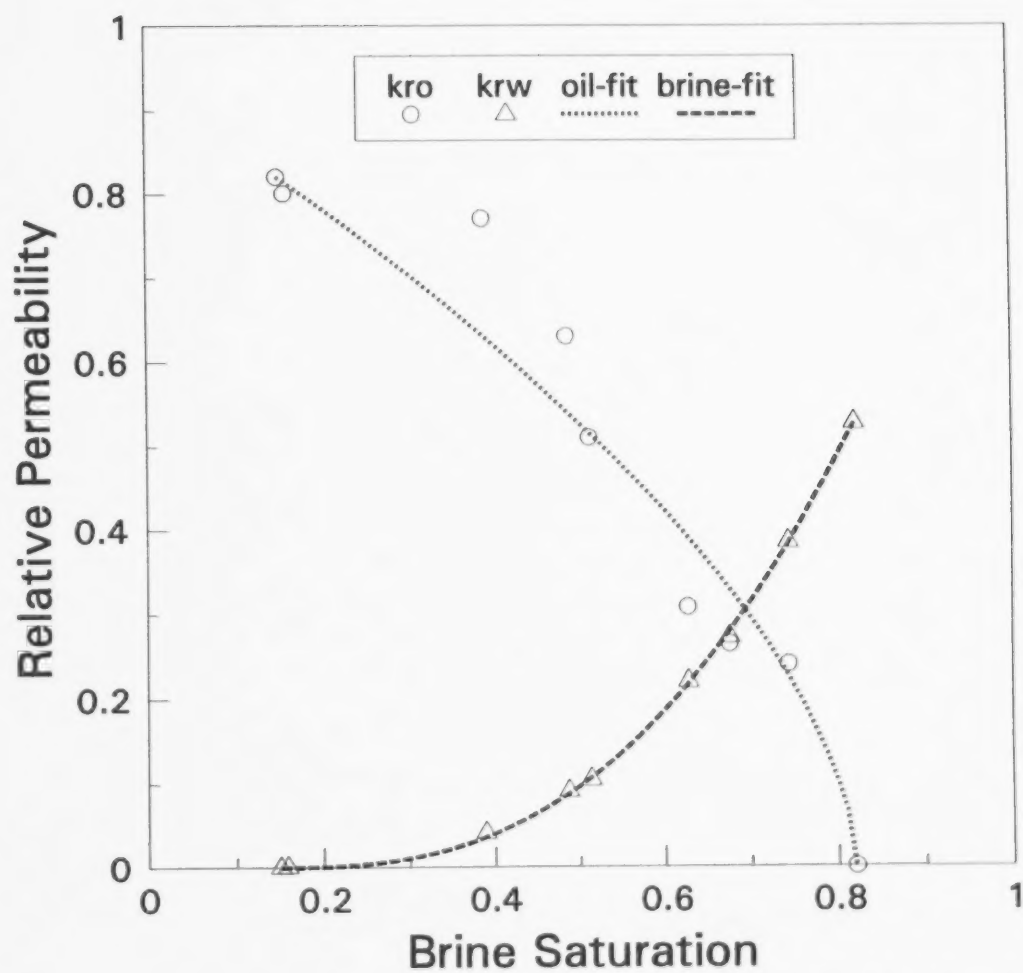


Figure 5.2 :Brine/Oil Two-Phase Relative Permeability at 125 °C

point oil and gas relative permeabilities along with the irreducible brine and the residual oilsaturation are given in Table 5.2. The experimental data points are shown in Figures 5.3 and 5.4.

5.3 Relative Permeability Curves

The steady-state relative permeability data thus obtained were fitted with power law functions using all the data points. The scatter in the experimental data was attributed to error in pressure drop and saturation measurements. To determine the individual phase relative permeabilities at each temperature, the following functional forms were used:

Oil/Brine experiments:-

$$\text{Oil: } k_{row} = k_{row}^o \left[\frac{S_w^{A_w} + B_{ow} \overline{S_w}}{1 + B_{ow}} \right] \quad (5.1)$$

$$\text{Brine: } k_{rwo} = k_{rwo}^o \left[\frac{(1 - \overline{S_w})^{A_w} + B_w(1 - \overline{S_w})}{1 + B_w} \right] \quad (5.2)$$

Oil/Gas experiments:-

$$\text{Oil: } k_{rog} = k_{rog}^o \left[\frac{S_g^{A_g} + B_{og} \overline{S_g}}{1 + B_{og}} \right] \quad (5.3)$$

$$\text{Gas: } k_{rgo} = k_{rgo}^o \left[\frac{(1 - \overline{S_g})^{A_g} + B_g(1 - \overline{S_g})}{1 + B_g} \right] \quad (5.4)$$

The parameters A_{ow} , B_{ow} , A_w and B_w were determined from the experimental data for oil and brine at 75°C and 125°C. Similarly A_{og} , B_{og} , A_g and B_g were determined from the experimental data for oil and gas at each temperature. The best fit results are presented in Tables 5.3 and

Table 5.2 : End-Point Oil/Gas Relative Permeabilities and Saturations

Parameters	T = 75°C	T = 125°C
k_{rog}^*	0.76	0.68
k_{rgo}^*	0.61	0.72
S_{wi}	0.103	0.08
S_{og}	0.22	0.221

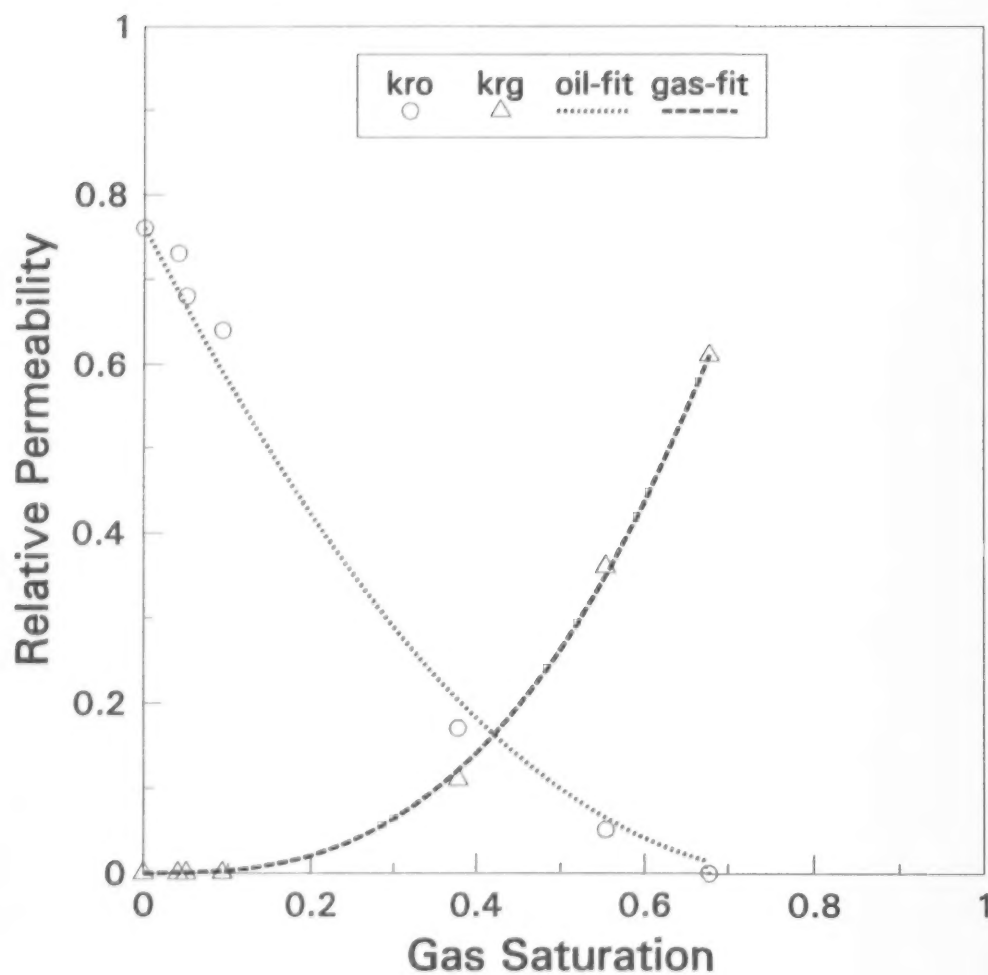


Figure 5.3 :Gas/Oil Two-Phase Relative Permeability at 75 °C

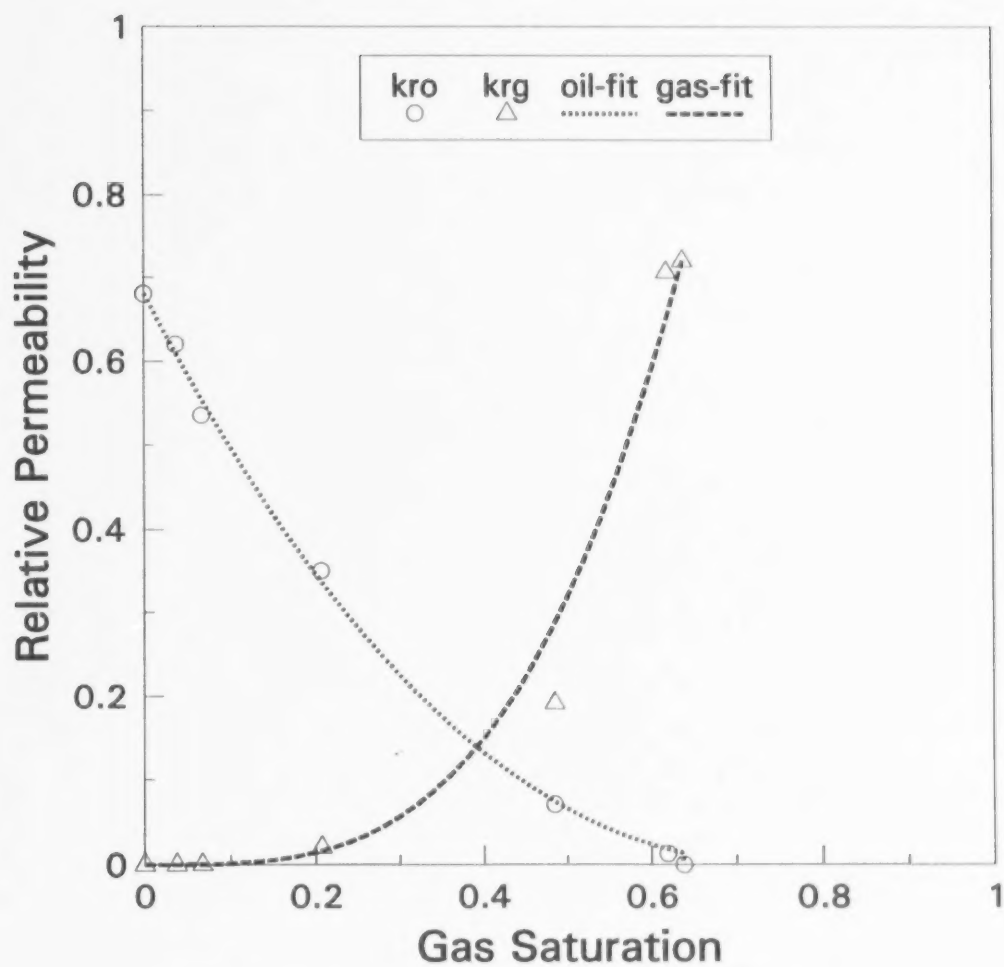


Figure 5.4 : Gas/Oil Two-Phase Relative Permeability at 125 °C

5.4, with the fitted curves shown in Figures 5.1 and 5.2.

The shape of the fitted curve deserves some attention. The brine curve is concave as usually reported in the literature. An exponent of 2.78 for 75°C and 2.61 for 125°C, which is not uncommon and which is widely accepted in the literature [Brooks and Corey, 1964; Delshad and Pope, 1989; Kokal and Maini, 1990], is required to fit the experimental data using Equation (5.2). The oil curve, on the other hand, is convex and the fit to Equation (5.1) has an exponent of 0.79 and 0.60 at 75°C and 125°C, respectively.

In the oil/gas relative permeability experiment, both the oil and the gas curve are concave as reported widely in the literature. An exponent of about 1.99 at 75°C and 2.27 at 125°C is required to fit the experimental data for oil using Equation (5.3). On the other hand, the fit to Equation (5.4) for gas has an exponent of approximately 2.78 and 3.36 at 75°C and 125°C, respectively.

Comparison between Figures 5.1 and 5.3 show much higher relative permeability values to oil when brine is the other phase than when gas is the other phase. This is to be expected, since the wetting phase (oil in gas/oil system and brine in brine/oil system) would occupy the smaller flow channels, and the nonwetting phases would reside in the larger flow channels which have a lower resistance to flow.

The shape of the relative permeability curves may vary, depending on the dominating mechanisms controlling multiphase flow through porous media. They are typically presented with concave curvature for all the phases [Honarpour, et al., 1986]. For heavy oils, this may not be true. Experimental results of the present study indicate that the shape of the oil curve in two phase oil/brine is convex (see Figure 5.2) especially at low brine saturations. The shape showed that oil recovery is rapid at the beginning of the imbibition runs, with further production tapering off. There is increasing evidence in the literature, based on theoretical and experimental reports, that the shape of the oil curve is convex rather than concave especially at low oil saturations [Sahimi et al., 1986; Talash, 1976]. A convex curvature was also reported

Table 5.3 : Fitted Parameters for Oil/Brine Data

Parameters	Oil		Brine	
	T = 75°C	T = 125°C	T = 75°C	T = 125°C
A	0.789	0.596	2.780	2.607
B	0	0	0	0
r^2	0.993	0.971	0.993	1.0

Table 5.4 : Fitted Parameters for Oil/Gas Data

Parameters	Oil		Gas	
	T = 75°C	T = 125°C	T = 75°C	T = 125°C
A	1.988	2.273	2.782	3.356
B	0	0	0	0
r^2	0.996	1.0	1.0	0.997

by Cambarnous and Pavan[1968] for a mineral oil-brine-unconsolidated silica sand system. Their relative permeabilities were measured by the steady-state method at 40°C. The mineral oil-to-brine viscosity ratio was estimated to be higher than 70. In the experiments reported in the present case, the oil-to-brine viscosity ratio varied from 48 to 92 for the temperatures studied. Marek et al.[1991] obtained a concave oil relative permeability with a viscosity ratio of approximately 3 and also, Combarous and Pavan obtained a concave oil relative permeability curve with a less viscous mineral oil (viscosity ratio estimated at approximately 20). Also, Closmann et al.[1985] found the same behaviour at 196°C with unaltered Peace River bitumen (viscosity ratio of approximately 60). It appears, therefore, that the viscosity ratio may influence the shape of the steady-state oil relative permeability curve in an oil-brine-unconsolidated sand system.

5.3.1 Effect of Temperature on Two-Phase Relative Permeability

To assess the significance of the effect of temperature on two-phase relative permeability, a statistical Fisher's z analysis was conducted. This test was performed to determine whether the two correlation coefficients differ significantly from each other. A calculated z -value greater than the tabulated z^* -value would indicate a significant statistical difference between these populations (see Appendix B).

The relevant parameters for 98% confidence limits are shown in Table 5.5. The result of the analysis showed that two-phase relative permeabilities at each temperature were not significantly different from one another for the phases involved. Figure 5.5 shows the combined plot of the oil/brine relative permeabilities as a function of brine saturation. Similarly, Figure 5.6 depicts the combined plot of the oil/gas relative permeabilities as a function of gas saturation.

A review of the literature shows a preference for the displacement technique to perform relative permeability experiments. The displacement technique yields a 'practical' residual oil

Table 5.5 : Statistical Analysis of Two-Phase Relative Permeabilities

		Temperature (°C)	No. of Data Points	Correlation Coefficient (r)	Fisher's z (z')
Oil/Brine	Oil	75	7	0.993	1.109
		125	9	0.971	(2.33)
	Brine	75	7	0.996	-2.301
		125	9	1.0	(-2.33)
Oil/Gas	Oil	75	7	0.996	-1.162
		125	7	1.0	(-2.33)
	Gas	75	7	1.0	1.618
		125	7	0.997	(2.33)

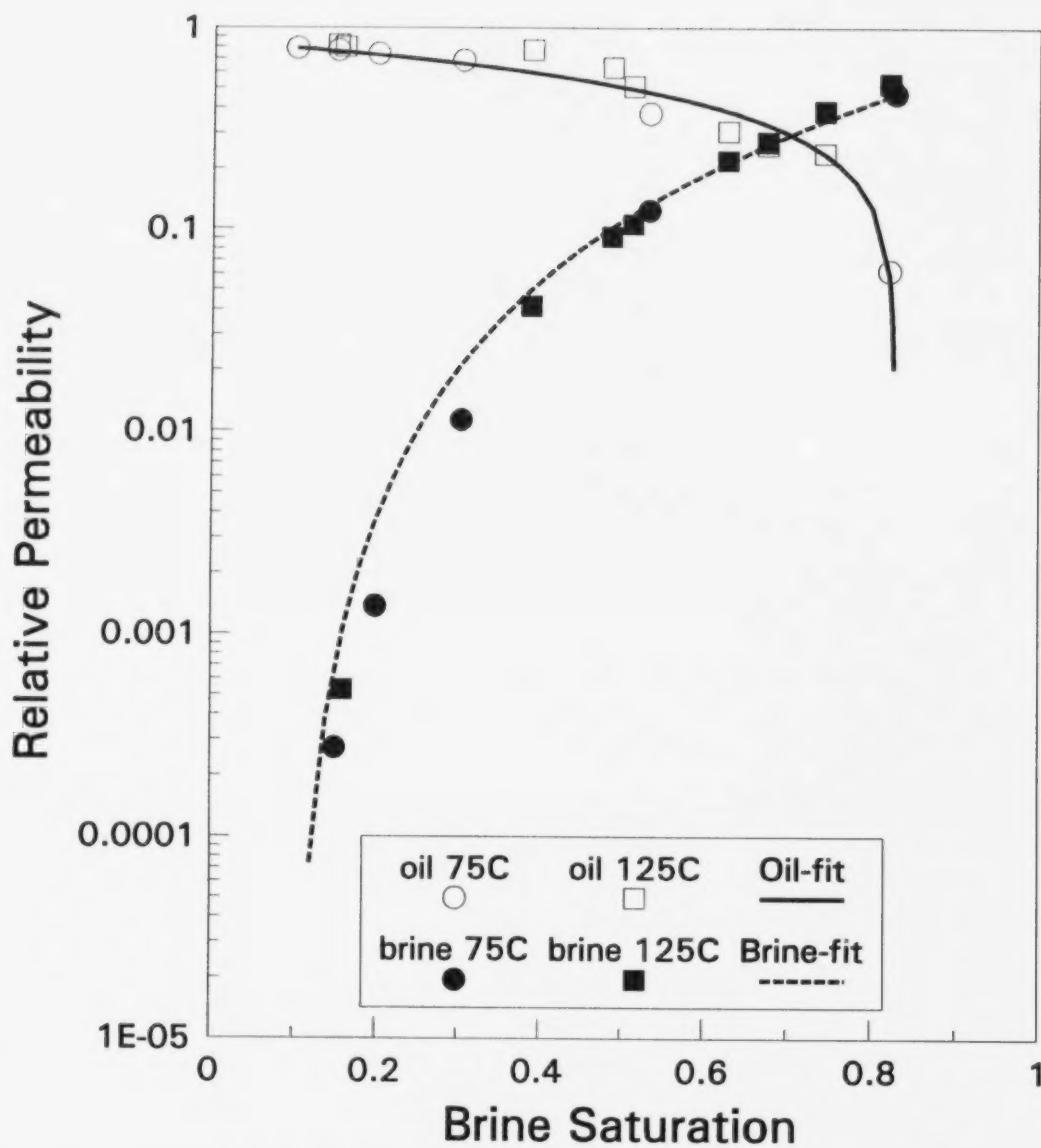


Figure 5.5: Two-Phase Oil/Brine Relative Permeabilities at 75°C and 125°C

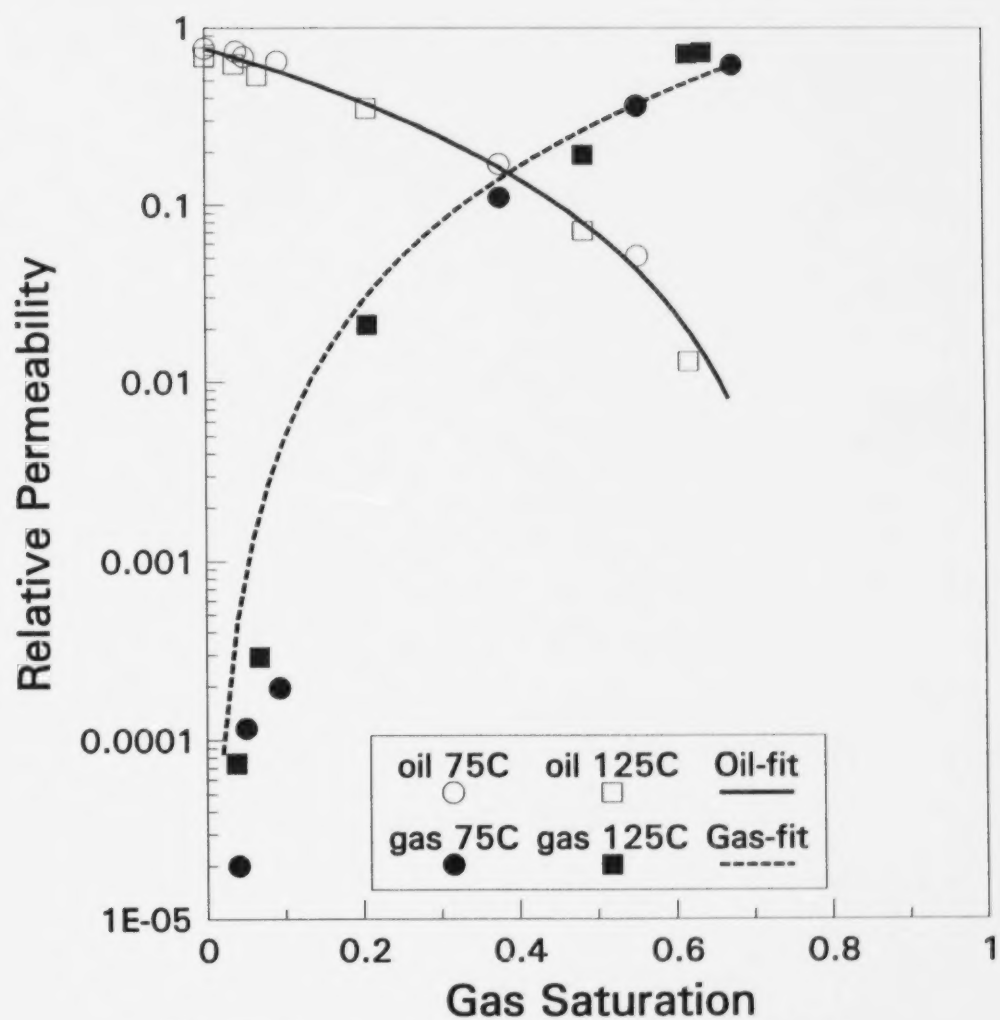


Figure 5.6: Two-Phase Oil/Gas Relative Permeabilities at 75°C and 125°C

saturation and a 'practical' irreducible water saturation because of the open loop system. Typical stopping criteria are a water-oil ratio (WOR) greater than 100 (for a waterflood), a WOR less than 0.01 (for an oilflood), or 10 pore volumes of displacing fluid injected. It is necessary to stop at this time because the error in the measurement of the displaced fluid accumulates and becomes excessive. However, for adverse viscosity ratios this can result in excessive error in the 'actual' residual oil saturation measurements. As shown below, the displacement technique assures the trends observed in other published works.

Using the two-phase data from this study, curves of mobility ratio versus saturation (refer to Figure 5.7) are generated using the equation;

$$m = \frac{k_{rw}\mu_o}{k_{ro}\mu_w} \quad (5.5)$$

The curves are generated assuming that the relative permeability is independent of temperature; however, because the viscosity change with temperature is much greater for oil than brine (approximately two times), the difference between the curves varies with temperature. Using a displacement technique, the measured residual oil saturation would be the saturation at a WOR (mobility ratio) equal to 100. This clearly results in a different 'apparent' residual oil saturation at each temperature, even though the relative permeability is assumed independent of temperature. The same is true of the irreducible brine saturation (saturation at WOR=0.01); however, the difference is not as large due to the favourable mobility ratio.

The effect of temperature on residual oil saturation for the data of Poston et al.[1970], Weinbrandt et al.[1975] and this study are plotted on Figure 5.8. Poston et al. used a 1.5 darcy unconsolidated sand and 80 and 600 mPa.s oils, while Weinbrandt et al. used 0.80 to 2.6 darcy consolidated cores and a 100 mPa.s oil. The residual oil saturations corresponding to a mobility ratio of 100 (at both temperatures) from Figure 5.7 are also included. This study

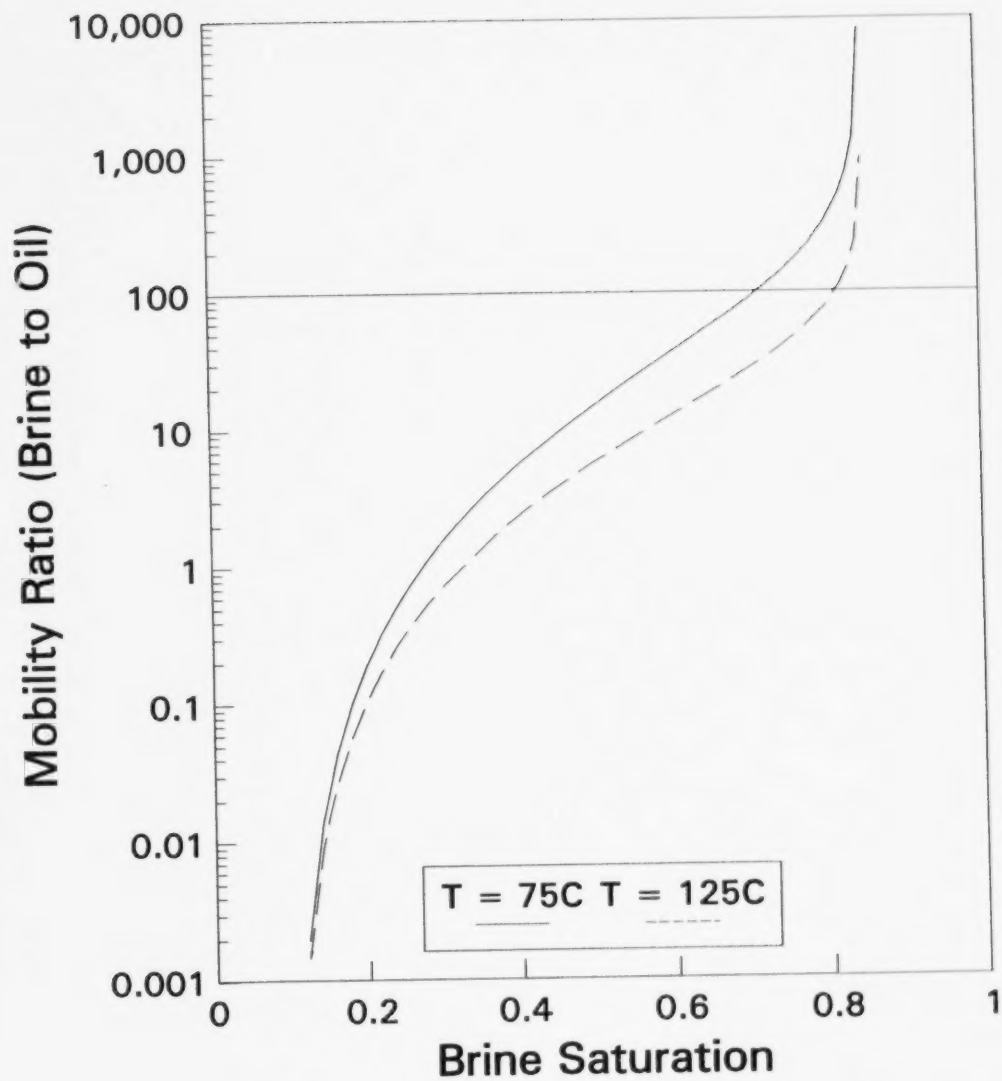


Figure 5.7: Brine-Oil Mobility Ratio versus Brine Saturation

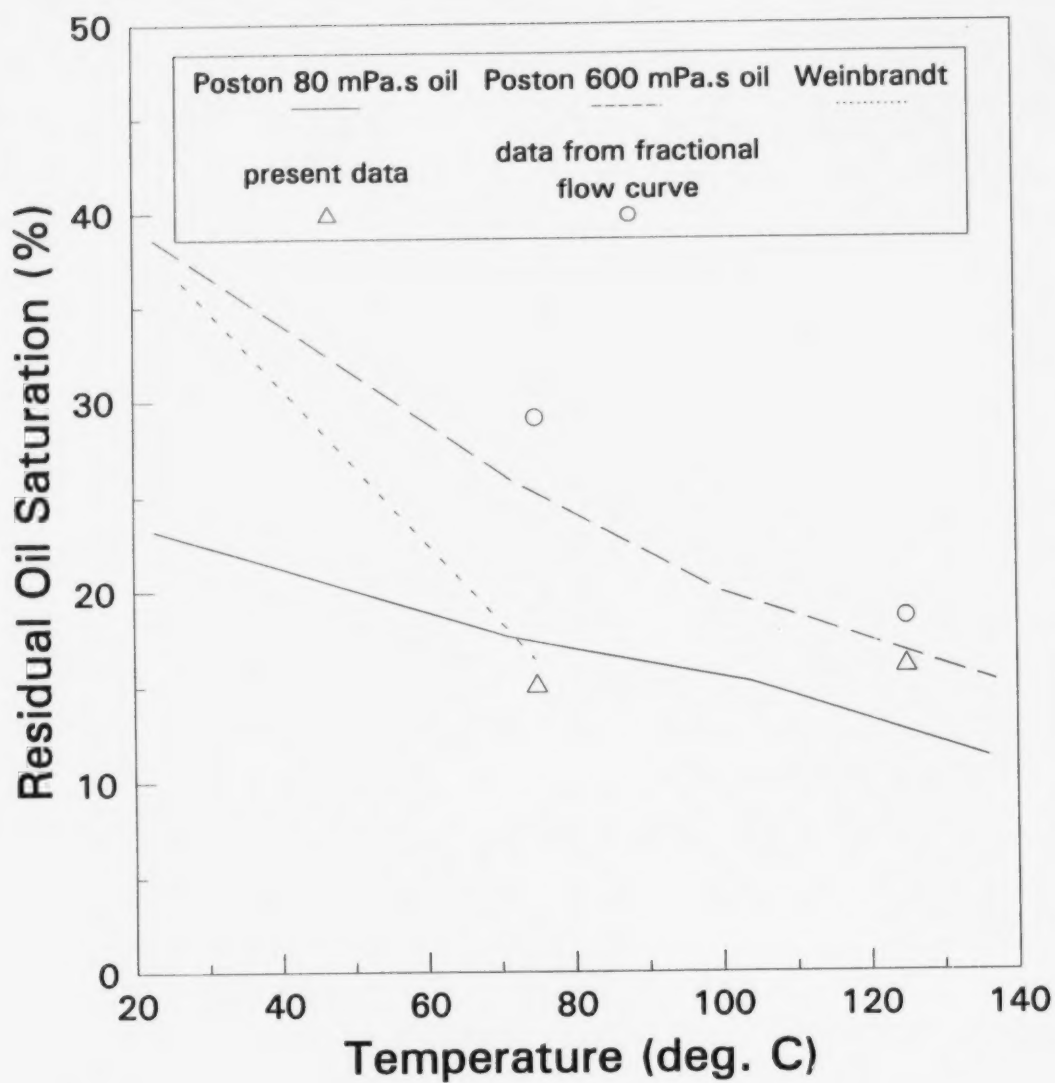


Figure 5.8: Residual Oil Saturation versus Temperature

concludes for this fluid-sand system that relative permeability is independent of temperature. However, when the data from the present study is put on a basis comparable to others, the same trends (residual oil saturation decreases with the increase of temperature) that have been reported by others can be generated. The authors of the previous papers apparently recognized the limitations of their results since they stipulated 'practical' saturations. There is no disputing their findings; however, some users of numerical simulators tend to ignore the term 'practical'. They [Chu and Trimble, 1975; Coats, 1976] adjust their relative permeability data which is input to the simulator for temperature effects in order to obtain a better match. As shown above, this change is due to changes in the viscosity ratio of the two fluids which is already included in the simulators. Sinnokrot et al. [1971] and Counsil and Ramey [1982] have presented some sources of inaccuracy in the previous studies.

As indicated previously, a number of investigators have reported increases in the 'practical' irreducible water saturations with an increase in temperature. These trends were not observed during this study; however, a different measurement technique was used. The irreducible water saturation determined at a mobility ratio of 0.01 from Figure 5.7 shows this trend.

Some of the anomaly in the work of previous investigators can be explained by the dependency of residual oil saturation on the ratio of viscous to capillary forces which pertains during the experiment. The dependence of residual oil saturation on the capillary and viscous forces present at the time of trapping was demonstrated by Moore and Slobod [1956] and verified by the extensive experiments of Abrams [1975] for water-wet porous media. Using concepts of dimensional analysis and scaling, Moore and Slobod [1956] proposed that the residual oil saturation should be a function of a dimensionless group representing the ratio of viscous forces to capillary forces and modified by Abrams [1975] (known as modified capillary number, N_{cm}) as defined by

$$N_{cm} = \frac{\text{viscous forces}}{\text{capillary forces}} = \frac{v\mu_w}{(S_{oi} - S_{or})\sigma_{ow}\cos\theta} \left(\frac{\mu_w}{\mu_o} \right)^{0.4} \quad (5.6)$$

As temperature increases, μ_o and σ_{ow} decrease, thus changing the ratio of viscous and capillary forces, and probably S_{or} . All sandstone correlations have a characteristic behaviour. At low values of the modified capillary number ($< 10^{-6}$), the residual oil saturation varies only slightly. This is the region where capillary forces dominate the viscous forces. Each sandstone has a distinct break that represents the transition from a displacement process dominated by capillary forces to one dominated by a competition between viscous forces and capillary forces. The transition occurs for values of N_{cm} in the range of 10^{-4} to 10^{-5} . Correlations are different for each rock type, as might be anticipated from rock properties. If the previous investigators had also presented the values of the capillary number, then the apparent decrease in the residual oil saturation may have been easier to explain.

5.4 Three-Phase Relative Permeability Experiments

After completing the two-phase tests, three-phase experiments were started at each of the temperatures. Six sets of experiments were conducted to cover the saturation ternary diagram as completely as possible. At one end high gas and low brine flow rates were used to reach the residual oil saturation. At the other end, low gas and high brine flow rates were used to reach the flood out (zero oil flow) condition.

The brine saturated core was oil-flooded until the irreducible brine saturation was reached. Then two-phase oil/brine flow was established with oil at a higher flow rate and brine at a lower flow rate. After establishing steady-state flow, gas was injected in such a way that there was no back flow of liquid into the gas flow line. This was achieved as follows. The prevailing pressure drop across the core was noted. The pressure drop across the end-effect absorbing section was calculated using the measured pressure drop across the core with the ratio of area and length between the main and end-effect absorbing sections. These two

pressure drops were added to the back pressure. The gas-line pressure was increased by that amount and then the gas-line valve to the core inlet was opened. This procedure resulted in no back flow of the liquids. In this way, three-phase flow was established in the core.

5.4.1 Three-Phase Brine Relative Permeability

Figures 5.9 and 5.10 show plots of brine relative permeabilities as a function of brine saturation, including the two-phase oil/brine data at 75°C and 125°C, respectively. The spread for the relative permeability to brine data was much less, the points falling close to a smooth curve that closely approximates those for the oil-brine system. This behaviour is typical for a strongly water-wet system. No consistent trends were found with the saturations of the other phases. Therefore, it was concluded that, for this system, the brine relative permeability is a function of brine saturation alone, and is not affected by the introduction of an additional nonaqueous phase. Also, there appears to be more scatter in the three-phase data than in the two-phase data. Furthermore, the scatter is more prominent in the low brine saturation range. It was attributed to the resistivity technique for brine saturation measurements. At low brine saturations, the resistivity technique does not give an accurate value for the saturation. But the scatter decreases as one approaches the higher end of the saturation range. One parametric equation can be used for both the two and three-phase relative permeability; also it has been mentioned previously that two-phase brine relative permeability is not a function of temperature. So, it can be inferred that three-phase brine relative permeability is also not a function of temperature. The combined plot is shown in Figure 5.11.

To test whether the two-phase and the three-phase brine relative permeabilities are the same, a statistical F-test was conducted. The F-test is used to determine whether the variances of two samples drawn randomly from the same population are equal or not. A calculated F-value greater than the tabulated F'-value for specified degrees of freedom would indicate a significant difference between these populations (see Appendix B).

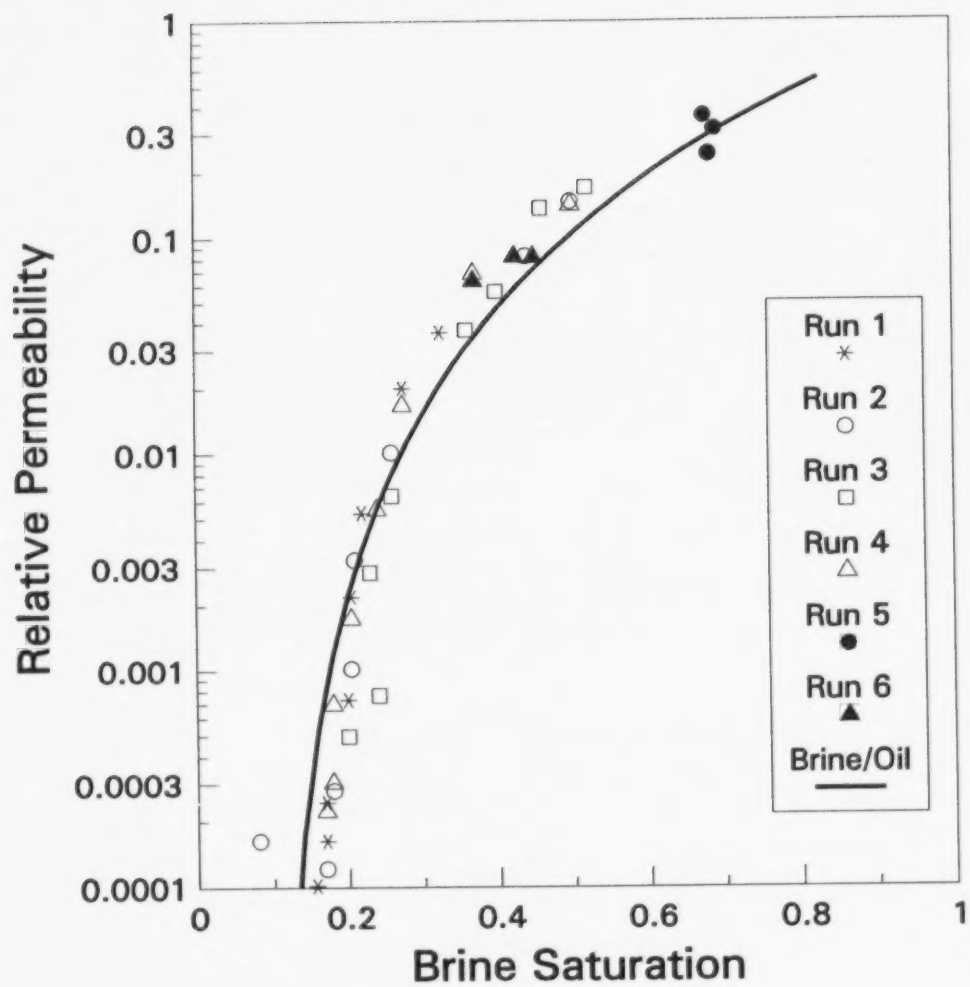


Figure 5.9 : Three-Phase Brine Relative Permeability at 75°C

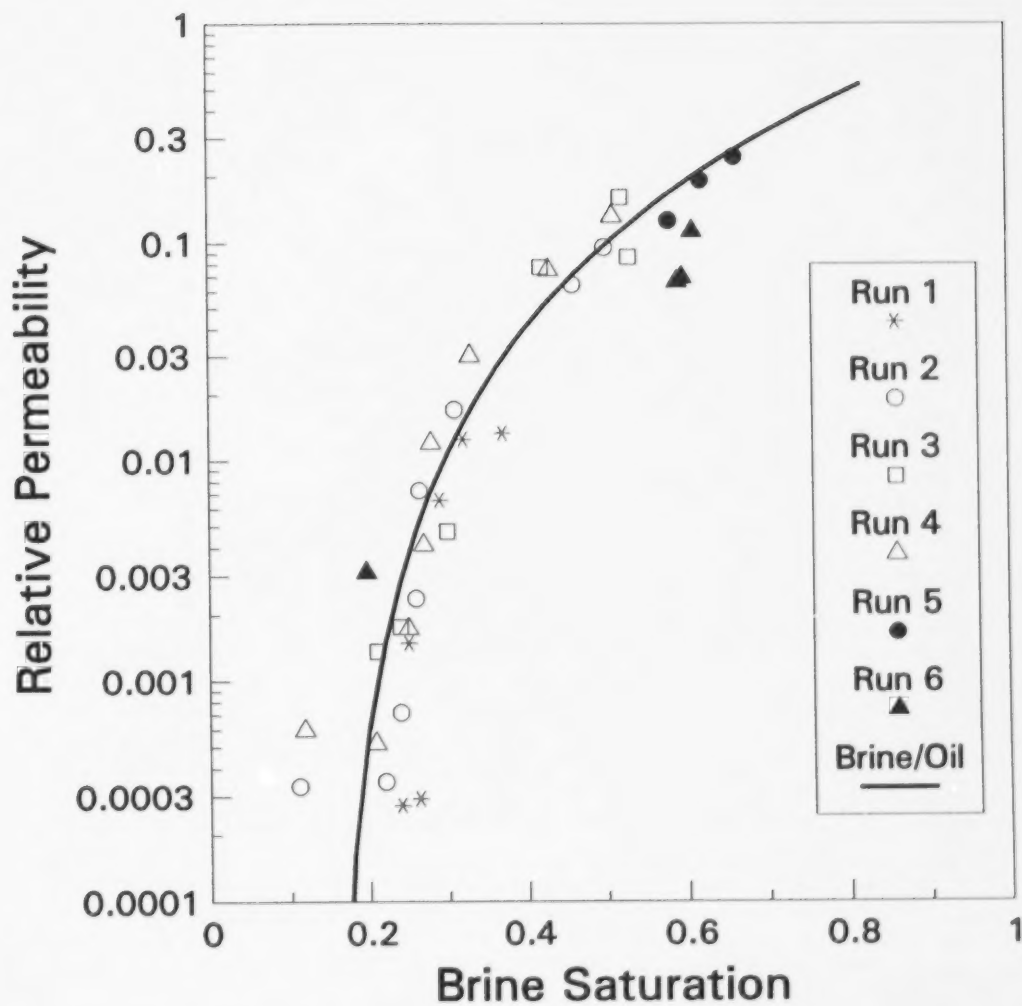


Figure 5.10 : Three-Phase Brine Relative Permeability at 125°C

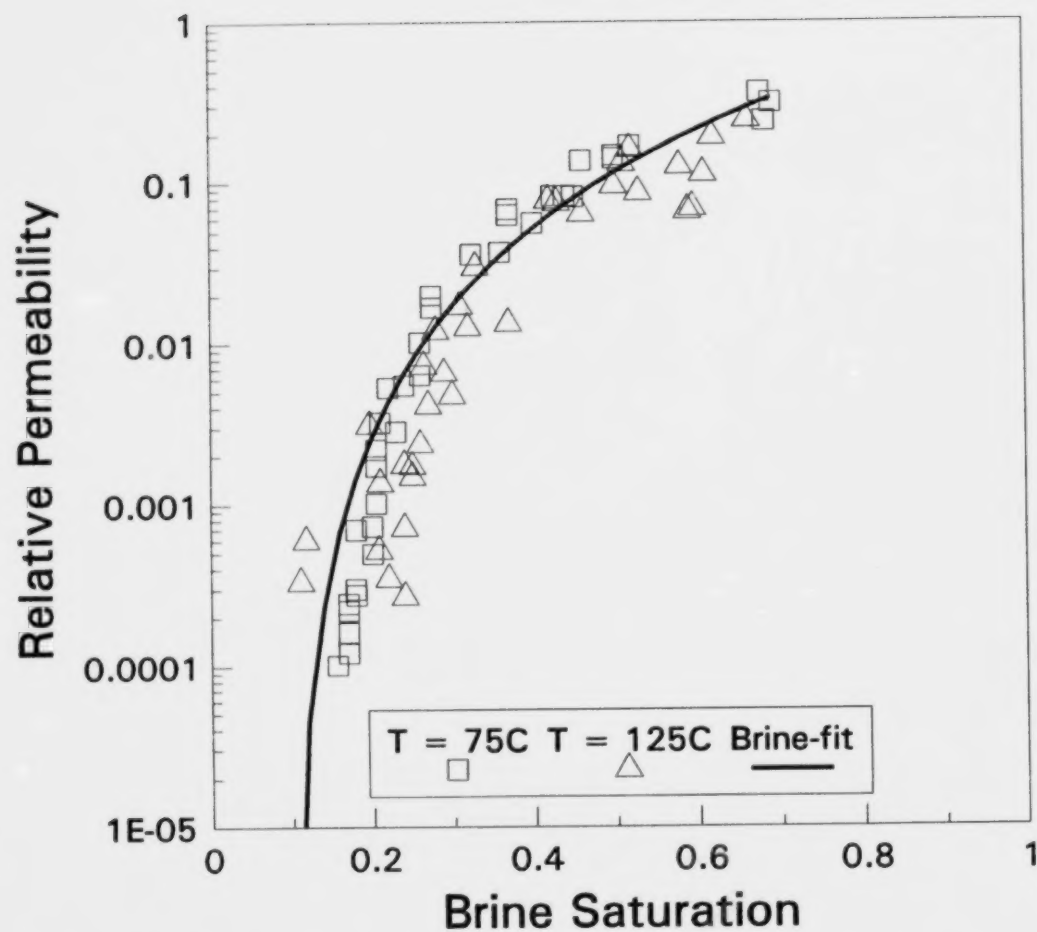


Figure 5.11 : Three-Phase Brine Relative Permeability at $75^{\circ}C$ and $125^{\circ}C$

The relevant parameters for specific degrees of freedom are shown in Table 5.6 for the 95% confidence interval. The result of the F-test showed that the two- and three-phase brine relative permeabilities belong to the same population. It further confirms the fact that brine relative permeability for the present water-wet system is a function of brine saturation only.

5.4.2 Three-Phase Gas Relative Permeability

Three-phase gas relative permeabilities as a function of gas saturation are shown in Figures 5.12 and 5.13. Two-phase gas relative permeabilities are also included on the plot. A considerable spread of the data was encountered in the relative permeabilities to gas. Also the relative permeability to gas in three-phase flow is less than would correspond to the same gas saturation in two-phase flow. This trend was always observed even when some of the experiments were repeated. This is in contrast with the conclusions of some of the previous investigators [Maini et al., 1989] and is in agreement with others [Leverett and Lewis, 1941; Oak et al., 1988].

It is quite clear that in Figures 5.12 and 5.13, each of the individual runs seem to fall on a different curve. The implication of this observation is that three-phase gas relative permeability depends not only on gas saturation, but also on oil and brine saturations. So, the three-phase gas relative permeabilities were replotted on a triangular diagram in the form of isoperms (as shown in Figures 5.14 and 5.15). Higher than 1% isoperms cannot be drawn because of few experimental points. The curvature of the isoperms is quite distinct and is concave towards the gas apex. In the present case of an unconsolidated Ottawa sand pack, the relative permeability to gas (Figures 5.14 and 5.15) at fixed gas saturations decreased as one moves away from the gas/brine axis; that is, some of the brine is replaced with oil. The gas relative permeability decreased initially with increases in oil saturation from 0 to about 40 percent, after which the permeability to gas increased with increasing oil saturation. Therefore, a definite decrease in gas permeability occurred when two other fluids were present.

Table 5.6a : F-Test for Brine Data

	Temperature (°C)	Number of Samples	Variance
Two-Phase	75	13	0.615
	125	13	0.577
Three-Phase	75	13	0.432
	125	13	0.251

Table 5.6b : F-test for Brine Data

	Degrees of Freedom		Two- Phase	Three- Phase	Same Temperature (°C)	
	Numer.	Denom.			75	125
F-value	12	12	1.066	1.72	1.424	2.30
F*-value (95%)	12	12	2.69	2.69	2.69	2.69

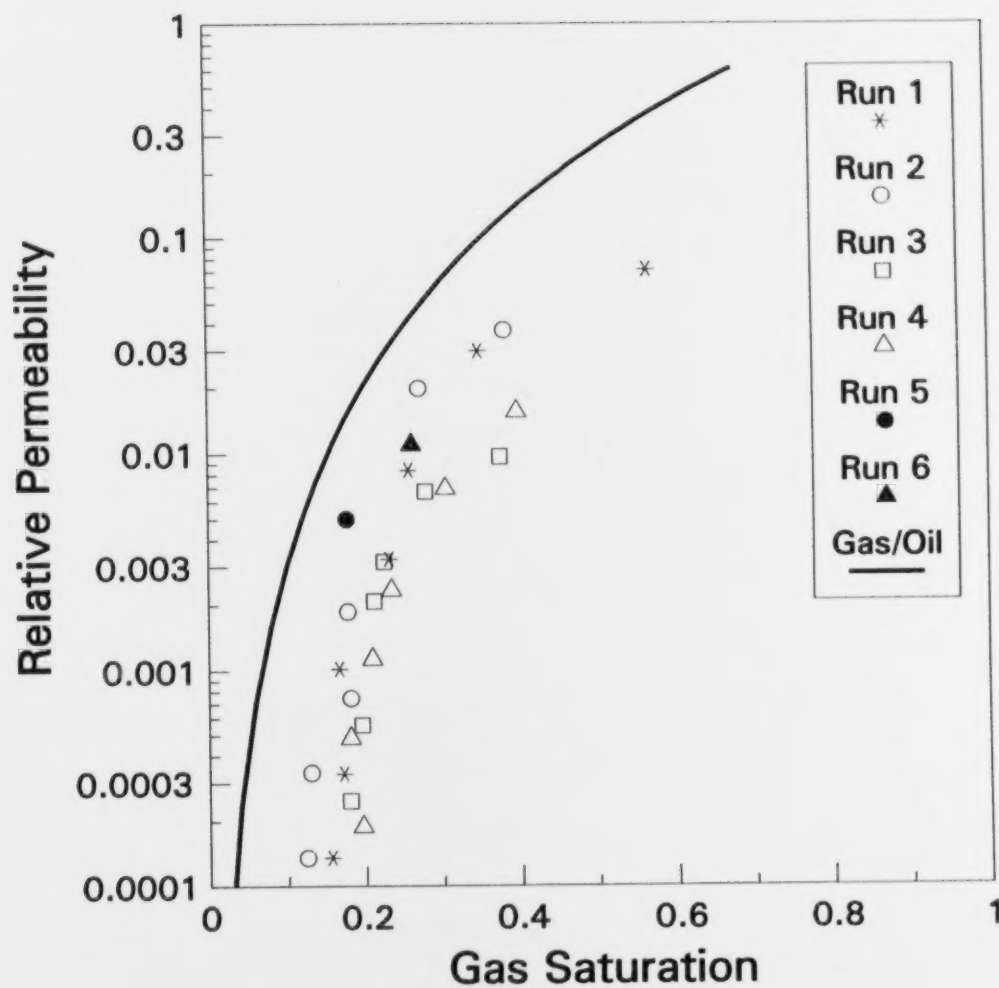


Figure 5.12 : Three-Phase Gas Relative
Relative Permeability at 75°C

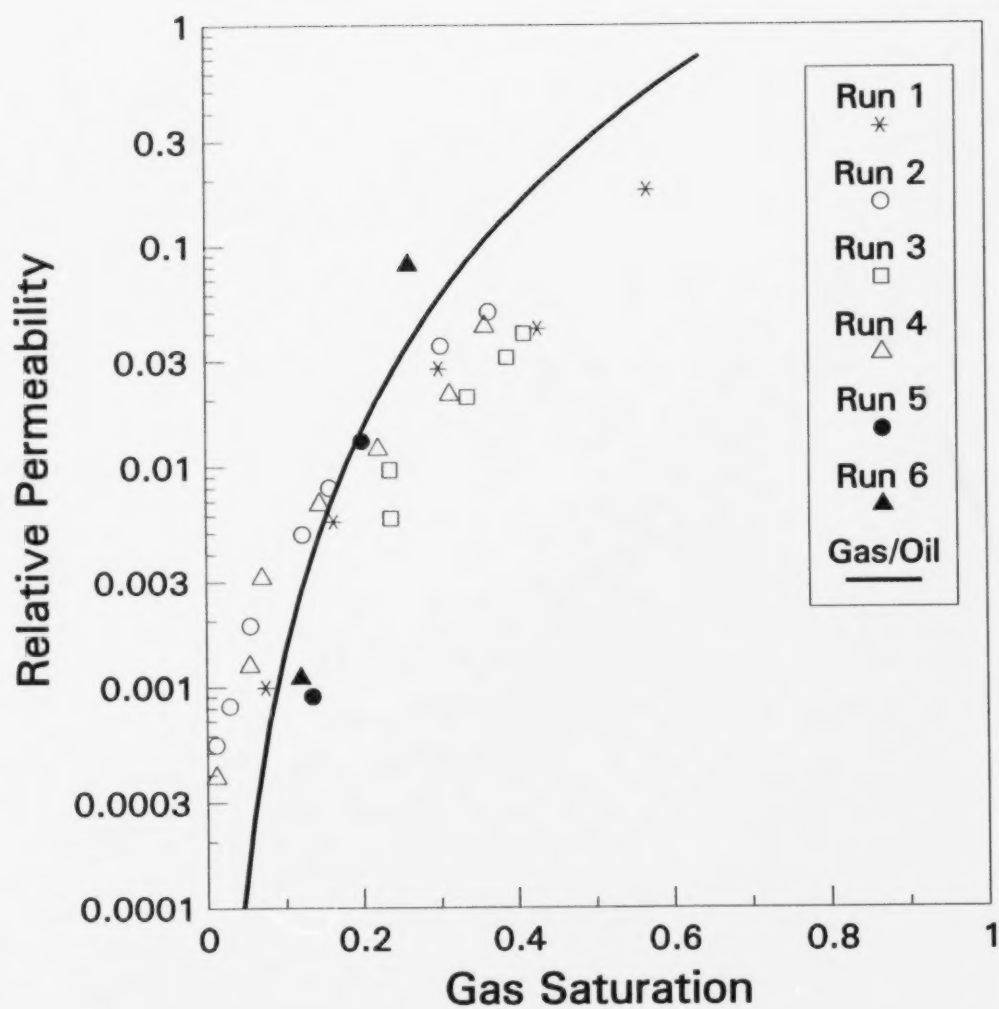


Figure 5.13 :Three-Phase Gas Relative Permeability at 125°C

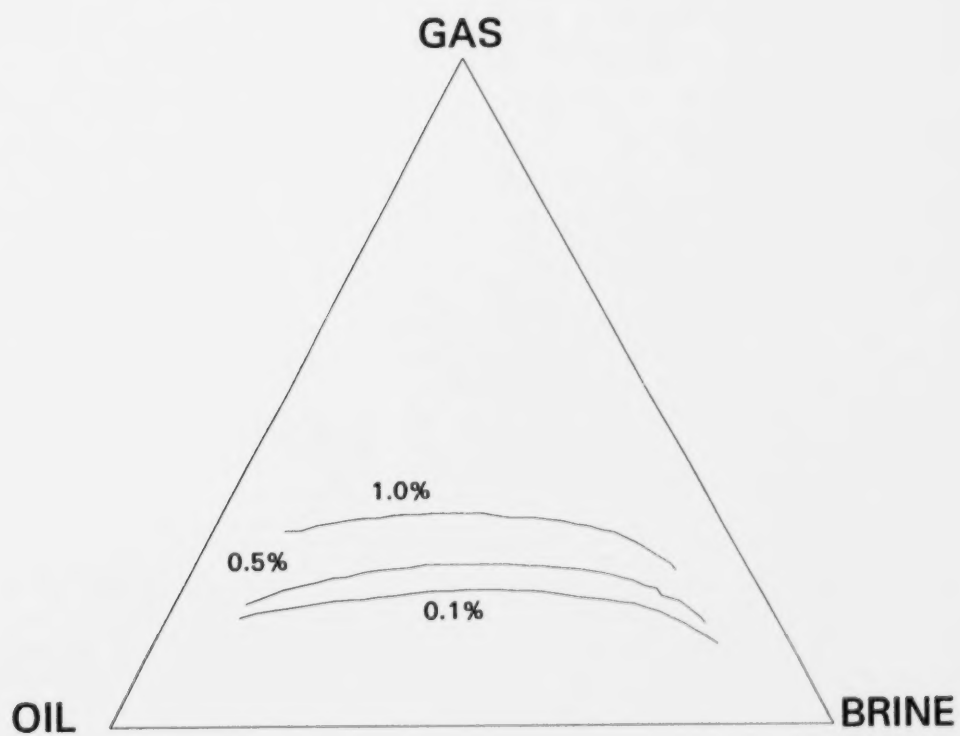


Fig. 5.14: Experimental Gas Isoperms at 75°C

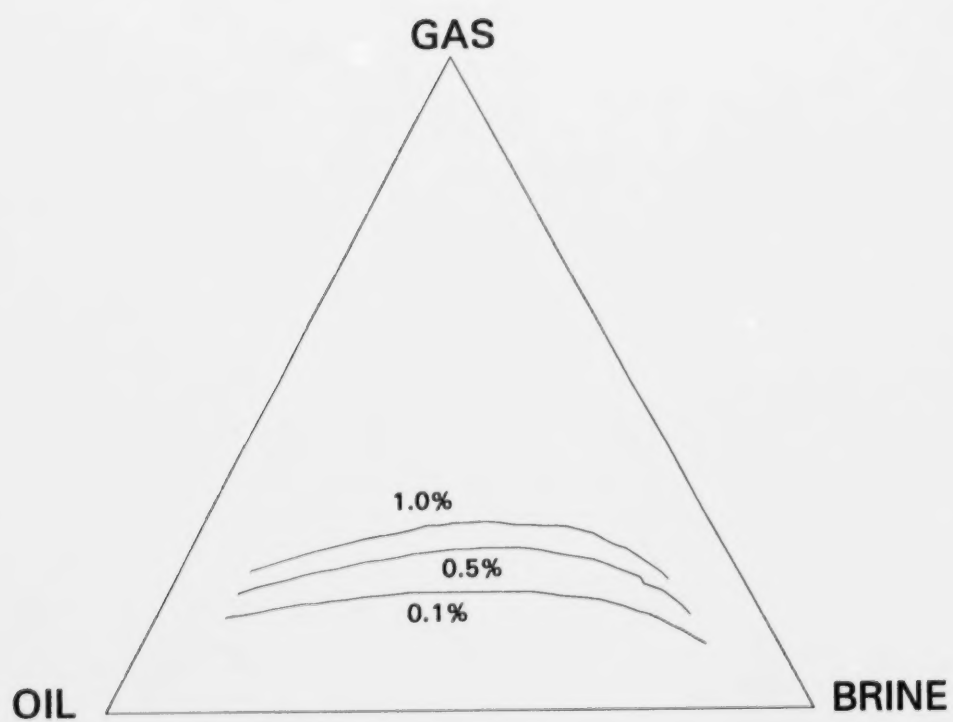


Fig. 5.15: Experimental Gas Isoperms at 125°C

Though the two-phase gas/brine relative permeabilities were not measured in the present case, one can follow the trend of the three-phase gas data in Figures 5.14 and 5.15; that is, the gas relative permeability decreases as one approaches the gas/brine axis. The reason for this type of behaviour is that relative permeability to gas at any gas saturation is lower in the presence of brine (wetting phase) than in the presence of oil (intermediate wetting phase) because of the higher surface tension of the brine phase allows brine to occupy the pores in such a way that the flow path of the gas is more restricted than it is in the presence of oil alone. To verify, from a statistical point of view whether the curves are different, an F-test was performed on the three-phase gas data (see Appendix B). The relevant parameters for 95% confidence interval are shown in Table 5.7. A calculated F-value for the specified degrees of freedom greater than the tabulated F^* -value would indicate a significant statistical difference between these populations (runs). From Table 5.7, it is apparent that the calculated F-value for runs at the same temperature are greater than the critical value. On the other hand, the calculated F-value for the runs at different temperatures having similar saturation trajectories are less than the tabulated F^* -value. These tests support two conclusions. First, the data points for the runs at the same temperature but having different saturation trajectories do not belong to the same population. Second, the data points for the runs at different temperatures but having the same saturation trajectories belong to the same population. These conclusions further confirm that, on the one hand, temperature has no effect on the three-phase gas relative permeability, and on the other hand, three-phase gas relative permeabilities are functions of all three fluid saturations.

The gas phase results of this study are compared with those of Schneider and Owens[1970]. Although different porous media were used in each investigation, several points support a qualitative comparison, given the current limited amount of available three-phase data. First, refined paraffinic oils were used in both cases. Second, the porous media, given

Table 5.7a: F-test for Gas Data

Degrees of Freedom				F-value (runs)		F'-value (95%)	
Numerator		Denominator					
75°C	125°C	75°C	125°C	75°C	125°C	75°C	125°C
11	8	11	6	3.626 (2/1)	4.408 (2/1)	2.98	4.21
11	6	11	6	15.09 (1/3)	7.958 (1/3)	2.98	5.05
11	8	11	6	54.72 (2/3)	35.08 (2/3)	2.98	4.88

Table 5.7b: F-test for Gas Data (Different Temperatures)

Degrees of Freedom		F-value	F*-value (95%)
Numerator (125°C)	Denom. (75°C)		
6	11	1.172	3.33
8	11	1.425	3.14
6	11	2.222	3.33

the experimental conditions, were water-wet. Thus, while a quantitative comparison cannot be justified, one could expect the brine/refined-oil/ N_2 -gas behaviour to be consistent between the two systems.

Schneider and Owens[1970] reported results of steady-state three-phase relative permeability measurements at room temperature and 1.38 MPa back pressure, for brine, a refined oil and N_2 gas in a water-wet Torpedo sandstone core. Figure 5.16 shows the Torpedo three-phase gas relative permeability results along with the data and the two-phase model curve from the present study. Schneider and Owens observed that their three-phase k_{rg} data (shown as the envelope in Figure 5.16) lie below their two-phase gas curve, which is consistent with the findings of this study. This same phenomenon is also noted for the Leverett and Lewis[1941] and Oak et al.[1988] results.

A statistical Fisher's z analysis showed that the three-phase gas relative permeabilities at 75°C and 125°C are not significantly different from one another. The combined plot at both temperatures is shown in Figure 5.17. There was considerable scatter in the data, especially at low gas saturations. It was speculated that at low rates of gas flow, the error in the measurements was high due to the fluctuations in the gas flow. This occurred despite waiting for a large amount of time for the system to reach steady-state. Also, during the experiment at 125°C, the compressed gas cylinder had to be changed for a fresh one. This might have contributed to the error in the measurements. But at higher gas flow rates, this was not a problem. Furthermore, the data follow the same trend at 75°C and 125°C, especially at gas saturations higher than 20%. So, emphasis was given to those points. The critical gas saturation for the present system was estimated to be at around 12%. On the other hand, the difference between the two data sets is exaggerated, especially at low gas saturations, because the data were plotted in log-linear curve. A statistical analysis showed that the points are within the 95% confidence interval of the mean curve. The relevant parameters are shown in Table 5.8. Therefore, it can be inferred that temperature has no effect on three-phase gas

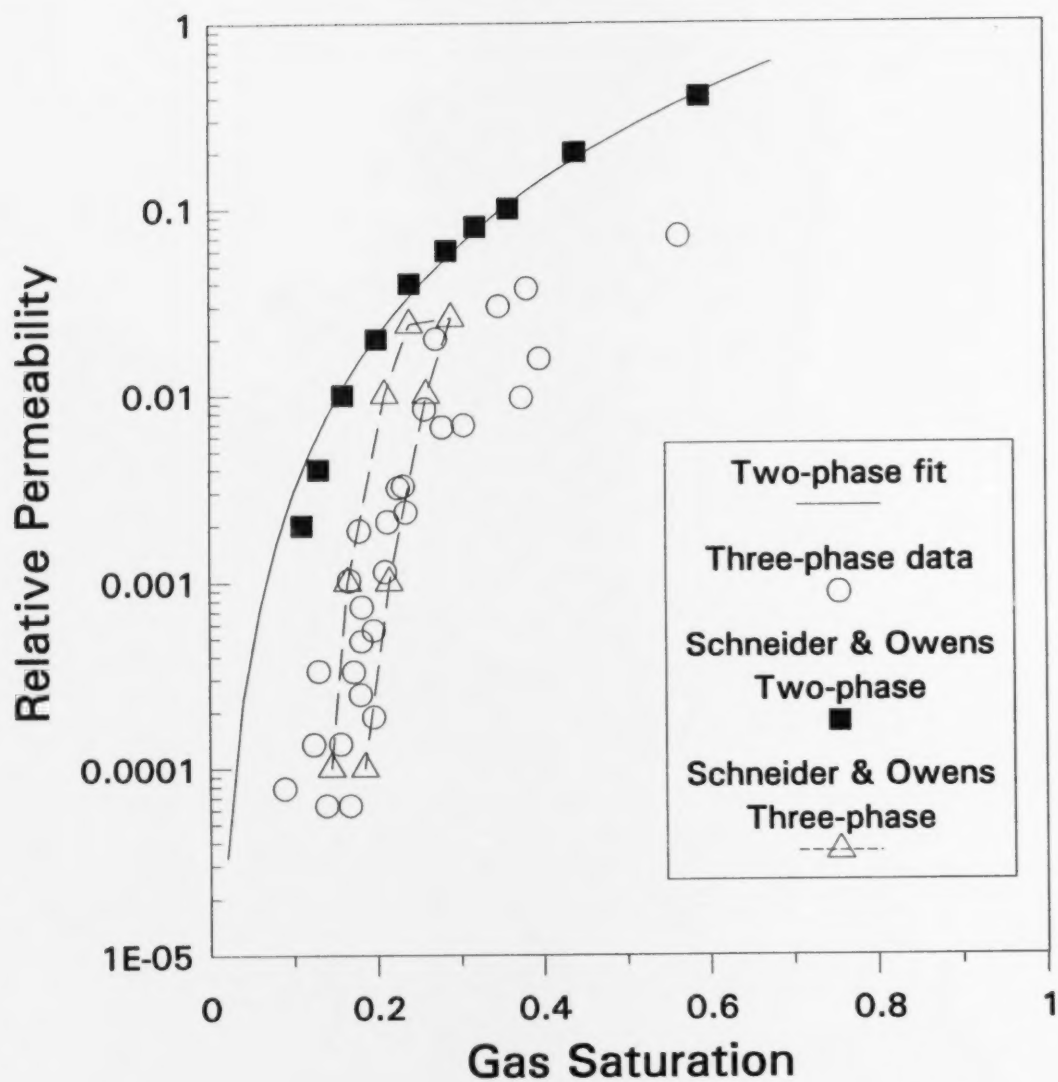


Figure 5.16: Three-Phase Gas Relative Permeability with Schneider & Owens Relative Permeability Data

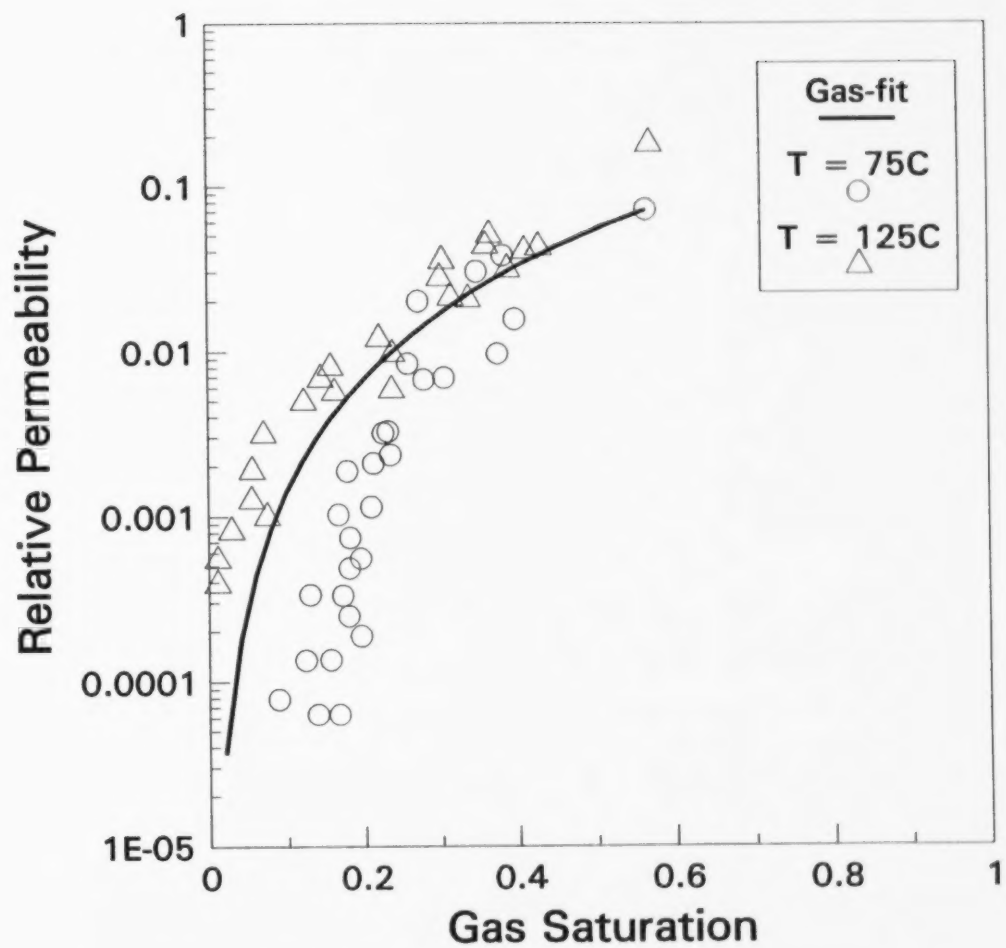


Figure 5.17 : Three-Phase Gas Relative Permeability at 75 °C and 125 °C

Table 5.8 :Statistical Analysis of Three-Phase Gas

Relative Permeability

Temperature (°C)	No. of Data Points	Correlation Coefficient (r^2)	Fishers z (z^*)
75	29	0.9327	-1.615
125	25	0.9731	(-1.96)

relative permeability.

5.4.3 Three-Phase Oil Relative Permeability

Figures 5.18 and 5.19 show plots of oil relative permeabilities as a function of oil saturation at 75°C and 125°C, respectively. The oil/brine measurements at zero gas saturation and the oil/gas measurements at irreducible brine saturation are included on the plot. There was considerable scatter in the data. Furthermore, the oil relative permeabilities from runs involving low gas saturations were closer to the oil/brine two-phase measurements and similarly those involving low brine saturations were closer to the oil/gas measurements. Therefore, the three-phase oil relative permeability data were replotted on a triangular diagram in the form of isoperms (lines of constant permeability). Although there was considerable scatter at higher oil saturations, the shape of the isoperms could be ascertained easily. The oil isoperms shown in Figures 5.20 and 5.21 are concave towards the oil apex. This observation supports two conclusions. First, the oil relative permeability is a function of all three fluid saturations. Second, the oil relative permeability is higher under three-phase flow conditions than under two-phase oil/gas conditions and lower than the two-phase oil/brine situation. This variation is generally attributed to one mechanism. When the gas saturation increases at a fixed oil saturation, oil moves to smaller and smaller pores because of the wettability difference with the gas phase. As a result, oil relative permeability decreases as gas saturation increases. This conclusion is supported by Figure 5.18. In this figure, oil relative permeability in oil/gas flow is less than that in oil/brine flow. Also, the increase in oil relative permeability at a fixed oil saturation as the saturation of the brine is increased is due to the shifting of the oil in the intergrain spaces where it flows freely because of low resistance. The brine occupies the surface adjacent to the grains and forces the oil to move to the central portion of the pores. As a result the oil permeability increases.

The oil isoperms at 75°C and 125°C are plotted together in Figure 5.22. The isoperms

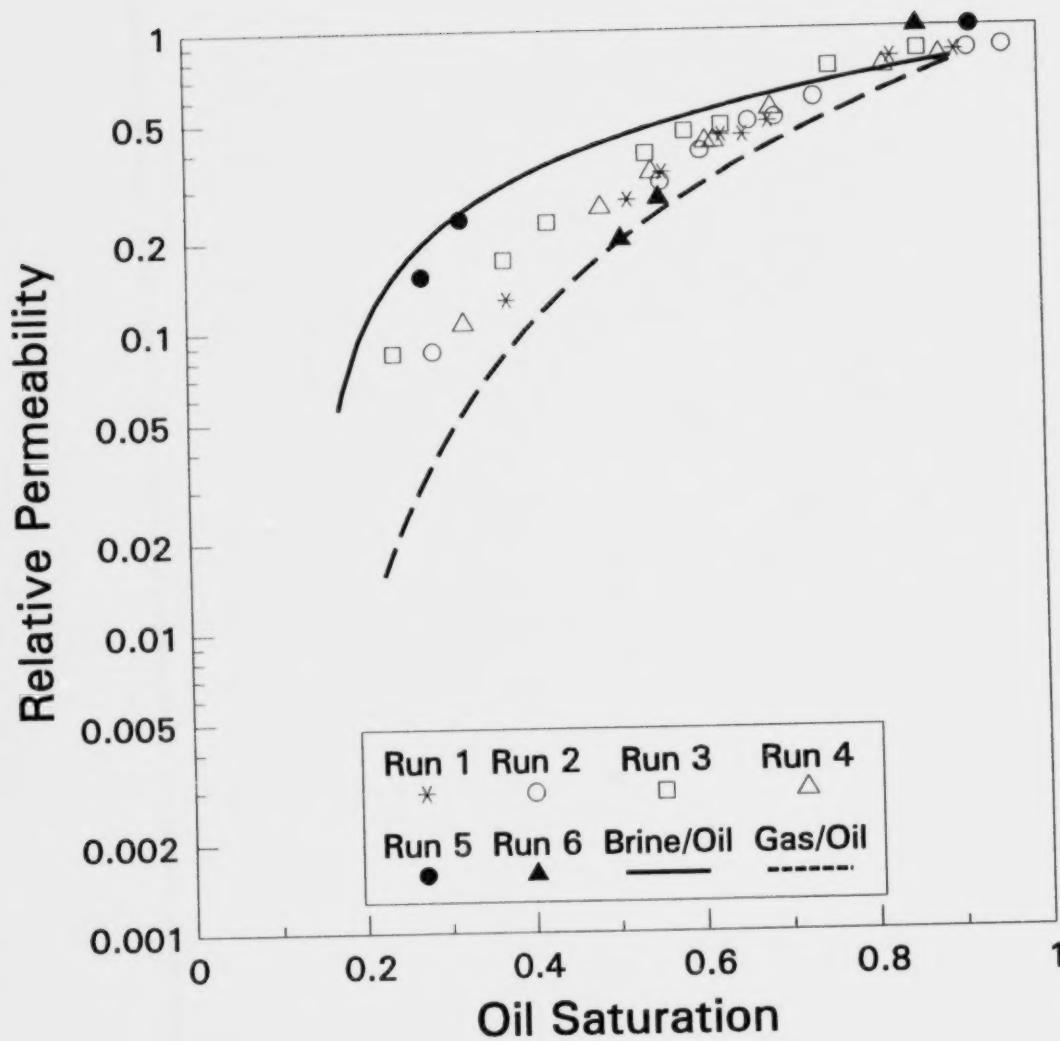


Figure 5.18 : Three-Phase Oil Relative Permeability at 75°C

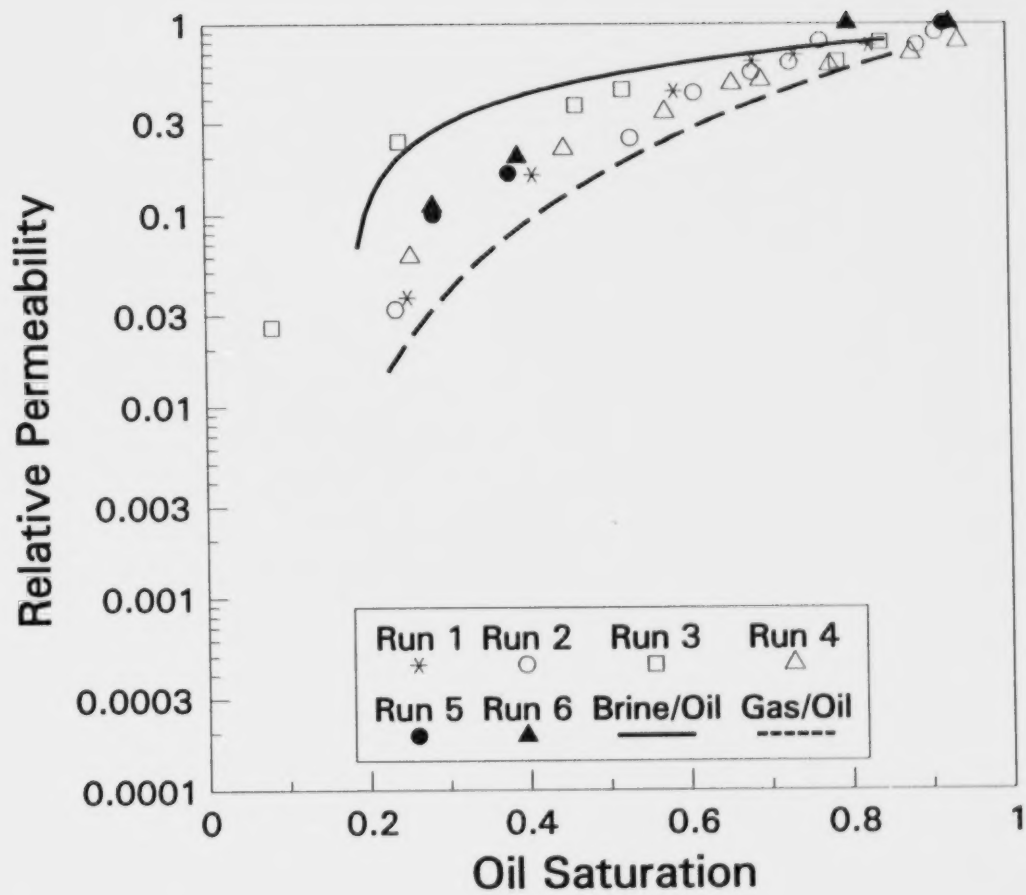


Figure 5.19 : Three-Phase Oil Relative Permeability at 125°C

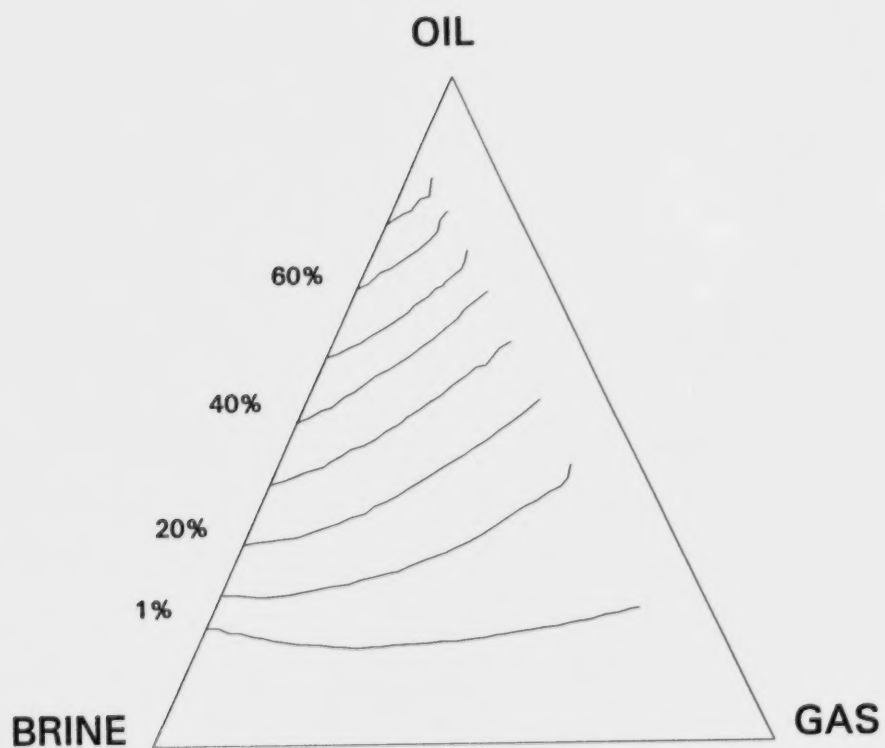


Figure 5.20 :Experimental Oil Isoperms at 75⁰C

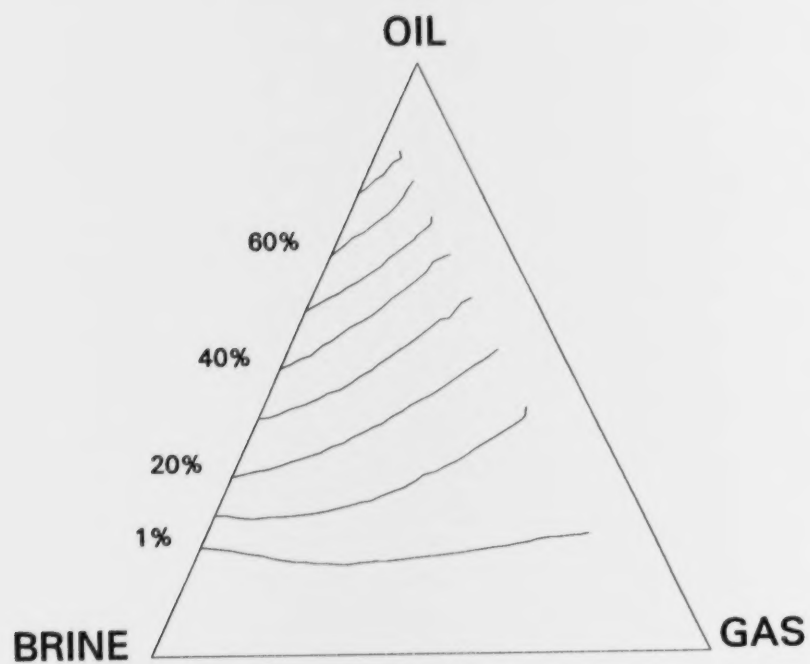


Figure 5.21: Experimental Oil Isoperms at 125 °C

Isoperms at 75°C

Isoperms at 125°C

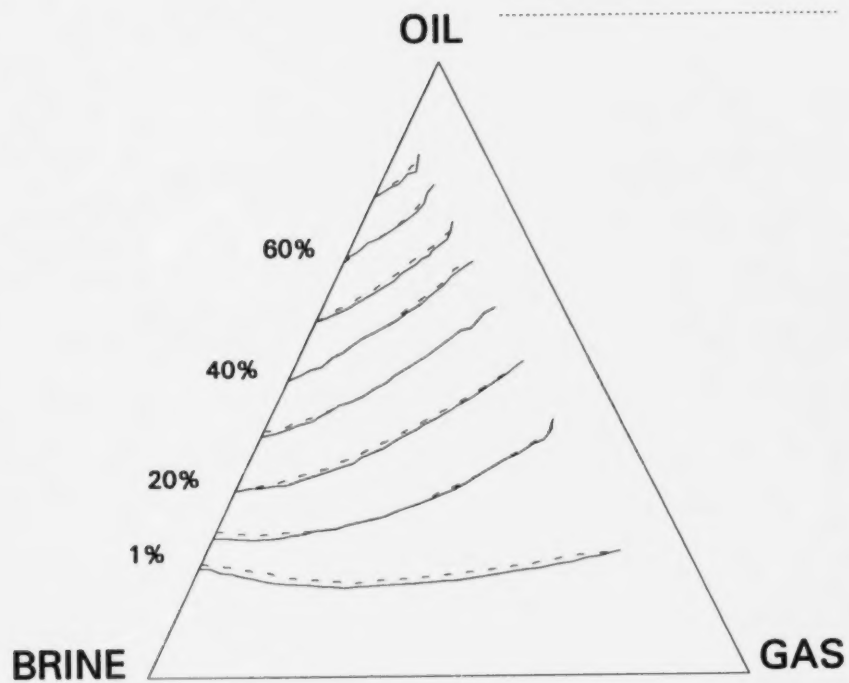


Figure 5.22 :Experimental Oil Isoperms at
75 °C and 125 °C

at the two temperatures almost coincide with each other, indicating that the oil relative permeabilities of the Ottawa sand pack are not affected by temperature.

To ascertain further, whether the three-phase oil relative permeabilities are indeed functions of all three fluid saturations, a statistical F-test was performed similar to that which was done in the case of three-phase gas relative permeabilities (see Appendix B). The concave shape of the oil isoperms is not as pronounced as those in the gas case; however, the shape was well defined as mentioned earlier. As the value of the F-test was close to that of the critical F^* value, the test was considered to be inconclusive.

5.4.3.1 Comparison with Stone's Method

The experimental results were compared with predictions obtained using Stone's method II[1970], as modified by Kokal et al.[1990], and Stone's method II[1974]. Figures 5.23(a, b) and 5.24(a, b) show the predicted values compared with the experimental results. A FORTRAN program is given in Appendix C for calculating the isoperms using the appropriate model. The prediction of Stone I was good for all isoperms at both temperatures. Kokal et al.[1990] also used their modified Stone I model to compare the predictions with several published experimental results. They found excellent prediction compared to the previous modifications of the Stone I. On the other hand, the predictions obtained using Stone II were consistently lower than the experimental values at both temperatures.

5.4.3.2 Comparison with Pope's Model

As both of Stone's models assume that the nonwetting-phase (gas) relative permeability is a function only of gas saturation, the above models are not applicable for the present study; however, they fit the data. The reason for this is that, in the present study, the three-phase gas relative permeability was found to be a function of more than one fluid saturation. So, an alternative prediction model was sought, which does not assume that gas

Experimental

Calculated

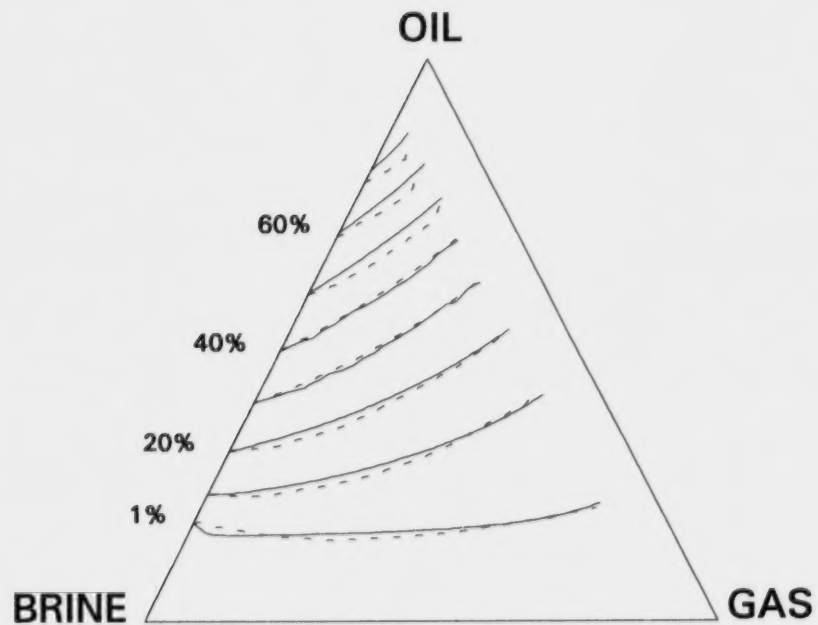


Figure 5.23(a) : Comparison with predictions
obtained using modified Stone
method I at 75°C

Experimental

Calculated

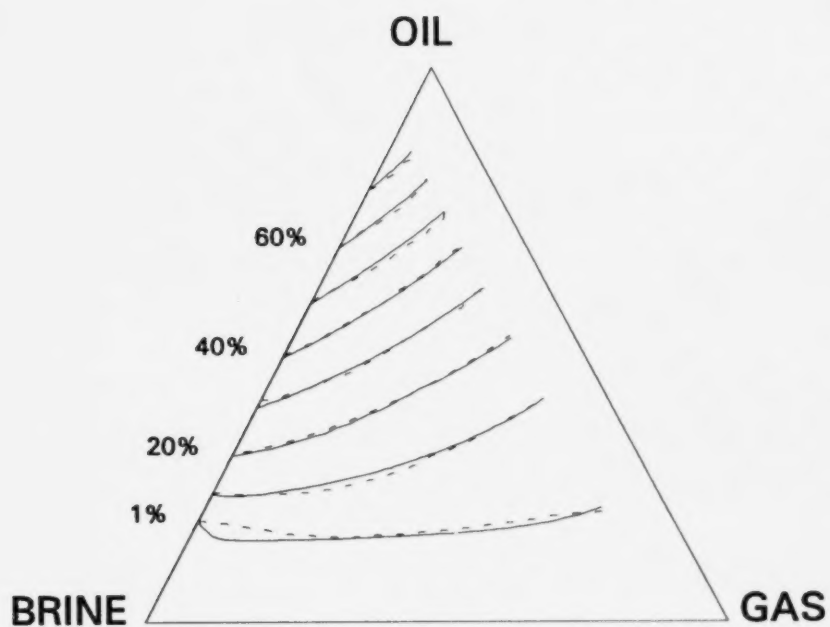


Figure 5.23(b) :Comparison with predictions
obtained using modified Stone
method I at 125^oC

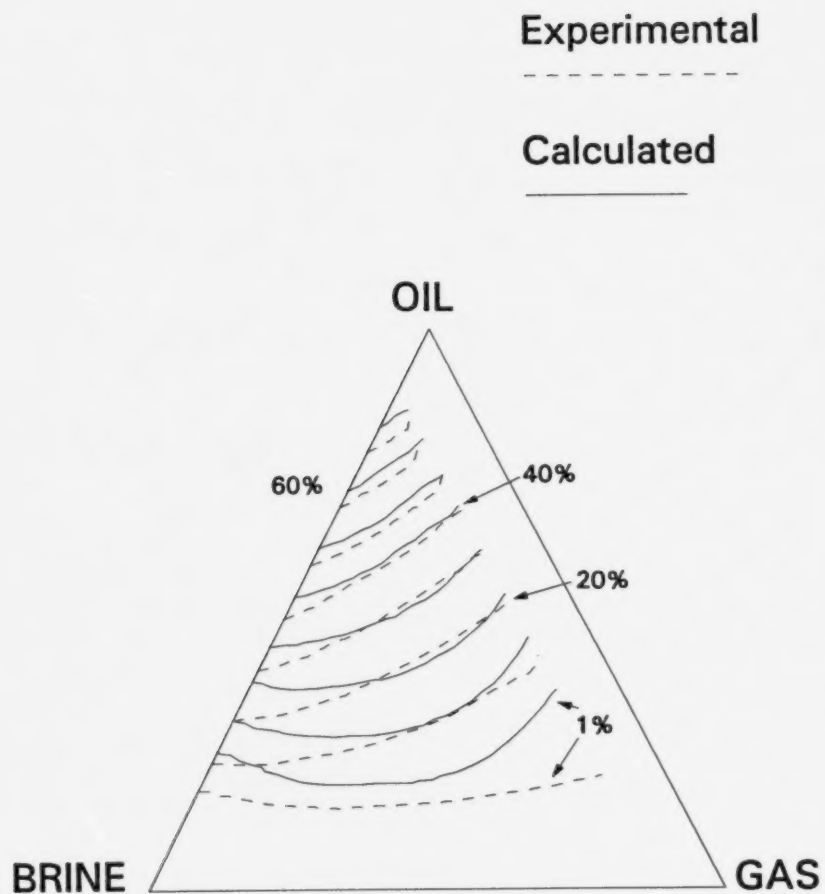


Figure 5.24(a) :Comparison with predictions
obtained using modified Stone
method II at 75°C

Experimental

Calculated

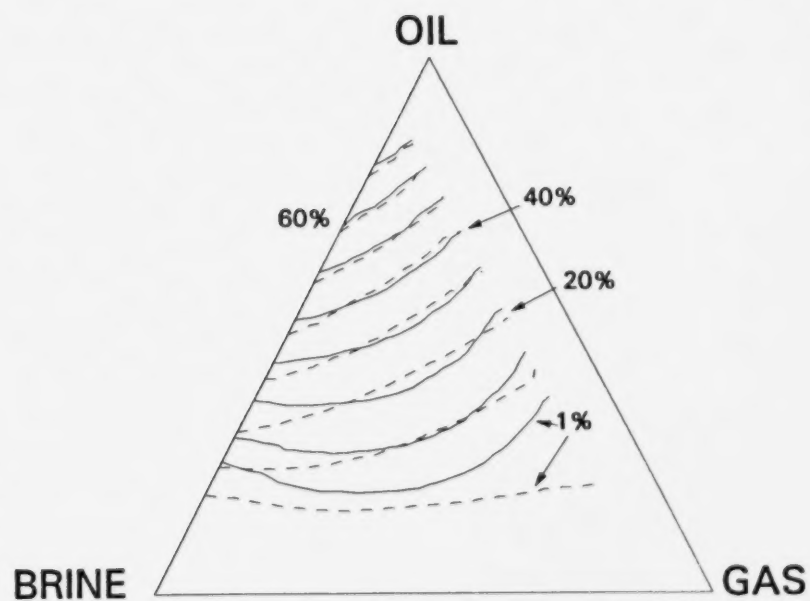


Figure 5.24(b) :Comparison with predictions
obtained using modified Stone
method II at 125°C

relative permeability is a function only of gas saturation. Delshad and Pope[1989] proposed a model for the prediction of three-phase oil relative permeability which is independent of the two-phase data. So, the experimental three-phase oil relative permeabilities were compared with the predictions obtained using the model of Delshad and Pope. Figures 5.25(a) and 5.25(b) compare the model with the experimental data measured at 75°C and 125°C, respectively. It is evident that, while the predictive and the experimental isoperms differ slightly at 75°C, the prediction is good at both temperatures for all of the isoperms. Moreover, the prediction is excellent at 125°C, especially for the higher isoperms.

5.5 Conclusions

In this study, the measured brine-oil-gas relative permeabilities showed no significant temperature effect within the range of temperature studied. Contrary to the case of two-phase flow, no published literature is available in this case; as a result, no comparison can be made regarding the results of this study. The lack of any significant temperature effect on three-phase relative permeabilities is attributed to the use of a clean porous network containing no clays. The type of oil is not the determining factor as similar results have been obtained using Blandol[Miller and Ramey, 1985] and white mineral oil[Sufi et al., 1982]. An ideal system, although not directly related to field operations, is more representative and useful for establishing the methodology for such complex measurements and obtaining reproducible and reliable results. A comparative study between an ideal (clean) and real (reservoir) systems can answer some of the questions on the effect of temperature on relative permeability relations. Maini and Batycky[1985] observed temperature effects to be less in horizontally drilled core plugs than in vertically drilled ones. They cited the occurrence of very thin shale layers as the reason for this difference. Bennion et al.[1985] reported lower permeability to water for a preserved core and reservoir fluids at a given saturation than those obtained using extracted cores and a mineral oil. It is possible that in the above experiments, the reactivity of the fluid-

Experimental

Calculated

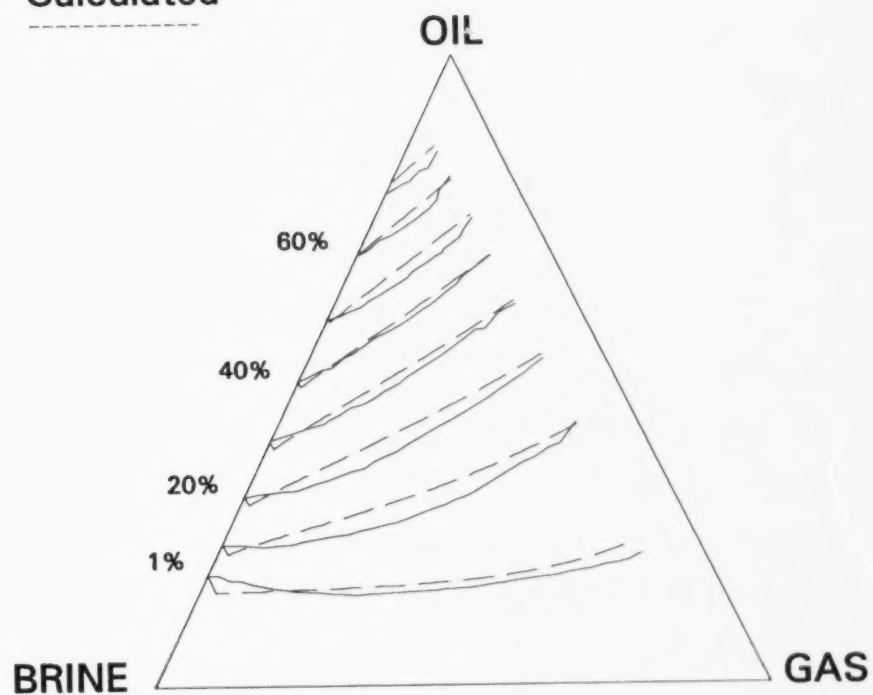


Figure 5.25(a) : Comparison with predictions
obtained using the Model of
Delshad & Pope at 75°C

Experimental

Calculated

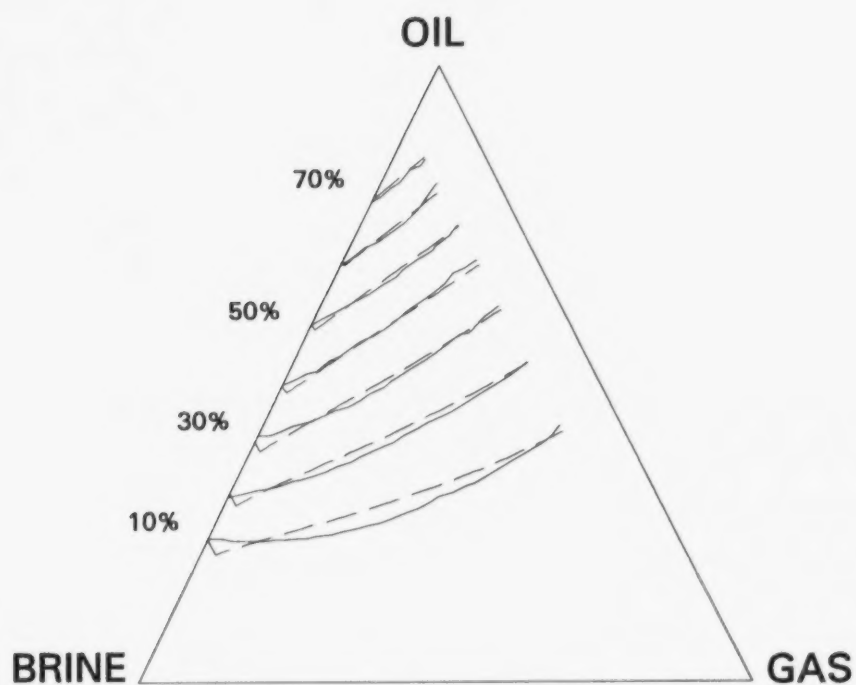


Figure 5.25(b) :Comparison with predictions
obtained using the Model of
Delshad & Pope at 125°C

solid combination might be responsible for the observed effects.

The steady-state experimental results obtained in this study were consistent with the findings of Maini et al.[1989] and Sufi et al.[1982]; the residual oil saturation and irreducible brine saturations were all similar. Even the nature of the relative permeability curves was similar except for the case of three-phase gas relative permeability. It was found that the relative permeability to gas in three-phase flow was less than would correspond to the same gas saturation in two-phase flow. The shape of the gas isoperms are convex towards the gas apex which supports the conclusions of the previous investigators[Leverett and Lewis, 1941; Snell, 1962; Donaldson and Dean, 1966; Caudle et al., 1951].

In light of the results obtained in this study, one can conclude that temperature effects on relative permeabilities are insignificant in a clean sand despite the large variation encountered in the fluid properties; however, these effects could exist for actual field systems.

Relative permeabilities represent the effects of pore geometry, wettability, fluid saturations and saturation history on interactions of viscous and capillary forces in the flow of two or more immiscible fluids through porous media. Reliable relative permeability data are required for numerical modelling of recovery schemes, and acquiring this data has become an important step in the planning and implementation of such processes. Although, in the case of heavy oil reservoirs, flow instabilities and viscous fingering can reduce the utility of laboratory derived relative permeabilities, such data are still valuable for understanding flow mechanisms and for defining the range of possible recoveries. Because, in addition to the properties of the porous medium, relative permeabilities are also affected by such factors as wetting characteristics of the fluids, saturation history and temperature, it is desirable to obtain measurements under reservoir conditions with reservoir fluids. For evaluations of thermal methods it is important to characterize the effect of elevated temperature on relative permeability.

Laboratory-determined relative permeability relations must account for the mechanisms

of the displacement process and be representative of the porous medium when used in field applications. Controlled experimental conditions that best simulate the reservoir must be used in the laboratory. In practice, carefully determined laboratory relative permeability curves on a small sample are used as input parameters to numerical simulators and their shapes are adjusted until a good match has been achieved for an entire field.

6. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

Up to now, no information is available on the effect of temperature on heavy oil-brine-gas relative permeability relationships. This is the first extensive study undertaken to determine heavy oil-brine-gas relative permeability at high temperatures and high pressures.

The following were successfully accomplished during the course of this research:

1. A laboratory flow apparatus was developed which could measure three-phase steady-state heavy oil-brine-gas relative permeabilities under high pressure, high temperature nitrogen flooding conditions.
2. Two-phase oil/brine relative permeabilities at zero gas saturation and two-phase oil/gas relative permeabilities at irreducible brine saturation were measured for an unconsolidated Ottawa sand pack.
3. A reproducible packing procedure was used. The sand packs were homogenous and yielded reproducible porosities (within 2%) and absolute permeability to brine (within 10%) when packed with sand of 140-200 mesh size. The measured properties were similar to values reported in the literature for the same type of porous medium.
4. During the course of this study, several modifications to the apparatus and experimental procedures were made to improve the quality of the data gathered.
5. A detailed statistical analysis was performed to determine whether the three-phase heavy oil-brine-N₂ gas relative permeabilities were dependent on temperature.
6. The experimental results were compared with predictions obtained using Stone's method I and II and the model of Pope.

From the results of this experimental study, the following conclusions are drawn:

1. For measurements taken along a well-defined and carefully followed saturation trajectory of brine saturation increasing, oil saturation decreasing and gas saturation

increasing, the relative permeability of brine is seen to depend on its own saturation. The gas and heavy oil relative permeabilities depend on the saturation of all three fluids.

2. No significant temperature effects were found for a heavy oil-brine- N_2 gas system in clean unconsolidated Ottawa sand packs.
3. The relative permeability to gas in three-phase flow was always less than that which would correspond to the same gas saturation in two-phase flow. This finding is in agreement with the three-phase Torpedo data of Schneider and Owens[1970]. This same phenomenon is also noted for the Leverett and Lewis[1941] and Oak et al.[1988] results.
4. The predictions obtained using Stone method I is good for both temperatures. However, those obtained using Stone II are consistently lower than the experimental values.
5. The comparative study shows that the agreement between the computed oil isoperms from the Model of Delshad and Pope and the experimental data of the present study is reasonably good.
6. No trend with temperature was observed for irreducible brine saturation (S_{wi}) and reducible oil saturation (S_{or}) for both two-phase and three-phase flow.

The following recommendations are made for further research:

1. Only a relatively small amount of data was collected along six saturation paths: three-phase, high temperature, high pressure relative permeability data should be collected along additional saturation trajectories which might be encountered in immiscible gas flooding. The saturation of the two nonwetting phases should be first varied monotonically, and then varied in such a fashion as to study systematically the hysteresis effects.

2. The fractional flow range studied should be extended so that the ranges of the three-phase relative permeabilities are extended to include higher values of relative permeabilities.
3. Gas-oil-brine types should be varied to observe the role of the spreading of one of the nonwetting phases on the surface of the wetting phase.
4. Experimental fluids and conditions should be varied to study the effects of changing interfacial tensions and viscosity ratios encountered in immiscible gas flooding.

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Appendix A
Ottawa Sand Pack Properties

Table A.1 : Core Dimensions and Packing Properties

Core/Run No.	Temperature (°C)	Sleeve length (cm)	Bulk volume (cm ³)	Pore volume (cm ³)	Porosity (ϕ) (%)
2-1.1	75	40.7	1017.5	397.5	39.1
2-1.2				375.0	36.9
3-1.1				379.0	37.3
3-1.2				391.5	38.5
3-1.3				378.0	37.2
3-1.4				391.5	38.5
3-1.5				393.5	38.7
3-1.6				401.0	39.4
2-2.1	125	40.7	1017.5	399.5	39.3
2-2.2				385.5	37.9
3-2.1				373.0	36.7
3-2.2				395.0	38.8
3-2.3				376.0	37.0
3-2.4				391.0	38.4
3-2.5				365.0	35.9
3-2.6				384.5	37.8

Table A.2 : Absolute Permeability

Core/Run No.	Temperature (°C)	Flow rate (cm ³ /min)	Pressure drop (kPa)	Absolute Permeability (darcies)
2-1.1	75	10.0	3.103	3.65
2-1.2			3.172	3.57
3-1.1			4.068	2.78
3-1.2			3.103	3.65
3-1.3			3.93	2.88
3-1.4			3.241	3.50
3-1.5			2.965	3.82
3-1.6			3.116	3.65
2-2.1	125	10.0	1.744	3.64
2-2.2			1.724	3.65
3-2.1			2.551	2.49
3-2.2			1.724	3.65
3-2.3			2.413	2.63
3-2.4			1.724	3.65
3-2.5			1.937	3.29
3-2.6			1.931	3.29

Appendix B
Statistical Analysis

The analysis presented here is intended to give an overview of some basic statistical definitions and calculation procedures used in this document. It is assumed that the data fall into an approximately normal distribution. Statistical inference is used to correlate the data by making statements about an entire population based on a random sample of observations from that population.

The average or mean, $\bar{x}$, of a sample of n observation is:

$$\bar{x} = \frac{\sum_{i=1}^n x_i}{n} \quad (\text{B.1})$$

The sample standard deviation, s , is given by:

$$s = \left[\frac{\sum_{i=1}^n (x_i - \bar{x})^2}{n-1} \right]^{0.5} \quad (\text{B.2})$$

In order to estimate the mean, m , of a population, and to find out how close $\bar{x}$ is likely to be to m , the concept of a confidence interval is used. A 95% confidence interval is calculated from the sample, which will cover the unknown population mean 95% of the time. The value 95% is defined as the confidence level of the interval. When the standard deviation of an entire population is unknown, the usual two-sided t confidence interval for the population mean is

$$\bar{x} - t^*(s/\sqrt{n}) \leq m \leq \bar{x} + t^*(s/\sqrt{n}) \quad (\text{B.3})$$

where t^* is the value found in a table of Student's t -distribution with $(n-1)$ degrees of freedom for the desired confidence level. The factor $(s/\sqrt{n})$ is also called the estimated standard deviation of the sampling distribution of $\bar{x}$. Furthermore, a t -test can be used as a tool to test hypotheses for individual population means, and for comparing two means.

To test the Null Hypothesis, H_0 , that a normal population has mean μ , use is made of

the t score or the t statistic

$$t = \frac{\bar{x} - \mu}{s} \sqrt{n-1} \quad (\text{B.4})$$

where $\bar{x}$ is the mean of a sample of size n . Suppose that two random samples of sizes n_1 and n_2 and are drawn from normal populations whose standard deviations are equal ($\sigma_1 = \sigma_2$). Suppose further that these two samples have means and standard deviations given by $\bar{x}_1$ and $\bar{x}_2$ and s_1, s_2 respectively. To test the hypothesis H_0 that the samples come from the same population (i.e. $\mu_1 = \mu_2$ as well as $\sigma_1 = \sigma_2$), use is made of the t score given by

$$t = \frac{\bar{x}_1 - \bar{x}_2}{\sigma \sqrt{\frac{1}{n_1} + \frac{1}{n_2}}} \quad (\text{B.5})$$

where

$$\sigma = \sqrt{\frac{n_1 s_1^2 + n_2 s_2^2}{n_1 + n_2 - 2}} \quad (\text{B.6})$$

One can think of a theoretical population coefficient of correlation denoted by ρ , which is estimated by the sample correlation coefficient r . Tests of significance or hypotheses concerning various values of ρ require knowledge of the sampling distribution r . For $\rho = 0$ this distribution is symmetric and Student's distribution can be used. For $\rho \neq 0$ the distribution is skewed. In such a case a transformation due to Fisher produces a statistic which is approximately normally distributed. The following tests summarize the procedures involved.

1. **Test of Hypothesis $\rho = 0$.**

Here use is made of the fact that the statistic

$$t = \frac{r \sqrt{n-2}}{\sqrt{1-r^2}} \quad (\text{B.7})$$

2. **Test of Hypothesis $\rho \neq 0$.**

Here use is made of the fact that the statistic

$$Z = \frac{1}{2} \log_e \left(\frac{1+r}{1-r} \right) \quad (\text{B.8})$$

where $e = 2.71828\dots$, is approximately normally distributed with mean and standard deviation given by

$$\mu_z = \frac{1}{2} \log_e \left(\frac{1+\rho}{1-\rho} \right) \quad (\text{B.9})$$

and

$$\sigma_z = \frac{1}{\sqrt{n-3}} \quad (\text{B.10})$$

The transformation (B.8) is called *Fisher's Z transformation*.

3. **Significance of a Difference between Correlation Coefficients**

To determine whether two correlation coefficients r_1 and r_2 , drawn from samples of sizes n_1 and n_2 respectively, differ significantly from each other, Z_1 and Z_2 are calculated corresponding to r_1 and r_2 using (B.8). Then use is made of the fact that the test statistic

$$Z = \frac{Z_1 - Z_2 - \mu_{Z_1 - Z_2}}{\sigma_{Z_1 - Z_2}} \quad (\text{B.11})$$

where

$$\mu_{Z_1 - Z_2} = \mu_{Z_1} - \mu_{Z_2} \quad (\text{B.12})$$

and

$$\sigma_{Z_1 - Z_2} = \sqrt{\sigma_{Z_1}^2 + \sigma_{Z_2}^2} = \sqrt{\frac{1}{n_1 - 3} + \frac{1}{n_2 - 3}} \quad (\text{B.13})$$

is normally distributed.

Tests to determine the equality of variances are based on a probability distribution called the *F distribution*. When one wants to compare data from two different populations, one may use the F-test. This is the theoretical distribution of values that would be expected by randomly sampling from a normal population and calculating for all possible pairs of sample variances, the ratios

$$F = \frac{s_1^2}{s_2^2} \quad (B.14)$$

where s_1^2 is the large variance and s_2^2 is the smaller [Davis, 1973]. The F-test is a statistical procedure that determines if the variation between populations is significantly different from the variation within a population, provided that there is a random sample from each population.

Then the critical F-ratio, F^* , is determined from an F-table distribution with the knowledge of the confidence interval, the degrees of freedom for the numerator and the denominator of the F-ratio. If F is larger than F^* , one concludes that there is a significant statistical difference between these populations.

Appendix C
Computer Programs

C.1: Program for Calculating 3-Phase Oil Isoperms

```
c
c   Program for calculating 3-phase oil isoperms using  Pope's model
c
implicit double precision (a-h,o-z)
double precision krow,krog,kro,krw,krq, krow0, krw0, krog0,krq0
character*20 filename
c
fkrow(s) = krow0*((s**aow + bow*s)/(1.0 + bow))
fkrog(s) = krog0*((s**aog + bog*s)/(1.0 + bog))
c
fkrw(s) = krw0*((s**aw + bw*s)/(1.0 + bw))
fkrg(s) = krq0*((s**ag + bg*s)/(1.0 + bg))
c
write(6,*)' Enter data file name '
read(5,99) filename
99 format(a20)
101 format(a20)
open (2,file = filename)
open (7,file = 'fort7')
open (8,file = 'fort8')
c
read(2,101)dummy
read(2,101)dummy
```

read(2,*)swi,sor,som,sog,kro

read(2,101)dummy

read(2,101)dummy

read(2,*)krow0,aow,bow

read(2,101)dummy

read(2,101)dummy

read(2,*)krw0,aw,bw

read(2,101)dummy

read(2,101)dummy

read(2,*)krog0,aog,bog

read(2,101)dummy

read(2,101)dummy

read(2,*)krg0,ag,bg

c

sw = 1.0-sor

25 continue

so = 1.0-sw

sg = 0.0

dsg = 0.01

dsw = 0.01

c 5 continue

a = 0.5

gam = aow

alp = aog

bet = gam-alp

del = alp-gam

```

5 continue

so = 1.0-sw-sg

sobar = (so-som)/(1.0-swi-som)

if(sobar.lt.0.0) sobar = 0.0

sgbar = sg/(1.0-swi-som)

swbar = (sw-swi)/(1.0-som-swi)

c

kro = krow0*(a*sobar**alp*((1.-swbar)**bet) + (1.-a)*
.   sobar**gam*((1.-sgbar)**del))

c

if(kro.lt.9.7d-03) goto 10

write(8,100)sg*100.0,so*100.0,sw*100.0,kro

100 format(3f10.3,f5.2)

sg = sg + dsg

so = 1.0-sg-sw

goto 5

10 continue

sw = sw-dsw

if(sw.eq.swi) goto 20

if(sw.lt.swi) sw = swi

goto 25

20 continue

stop

end

```


C.2: A Typical Data File

(1) Swi (connate water saturation), Sor (residual oil saturation), Som (minimum oil saturation),
Sog (residual oil in oil-gas), initial kro

0.1 0.173 0.143 0.22 0.01

(2) Input krow0, aow, bow. $Se = (1.0 - Sw - Sor)/(1.0 - Swi - Sor)$

$$krow = krow0 * (Se^{aow} + bow * Se) / (1.0 + bow)$$

0.786 0.789045 0.000000

(3) Input krw0, aw, bw. $Se = (Sw - Swi)/(1.0 - Swi - Sor)$

$$krw = krw0 * (Se^{aw} + bw * Se) / (1.0 + bw)$$

0.593 2.78019 0.000000

(4) Input krog0, aog, bog. $Se = (1.0 - Sg - Sog)/(1.0 - Sog)$

$$krog = krog0 * (Se^{aog} + bog * Se) / (1.0 + bog)$$

0.76 1.988823 0.000000

(5) Input krg0, ag, bg. $Se = Sg/(1.0 - Sog)$

$$krg = krg0 * (Se^{ag} + bg * Se) / (1.0 + bg)$$

0.61 2.78175 0.000000

C.3: Program to Calculate the Viscosity of Vitrea 150 Using Singh et al.[1990] Correlation

```
main()
{
    double lvis,is,ss,c,vist,temp,btol,bguess,bnew,bold;
    double ao,tq,ak,p,q,fb,fder,temp2,vis,s,b,sl,ssl;
    double power();

    char response = 'y';

    ss=0.28008;
    is=1.618;
    c=0.8696;

    printf("Enter Measured Viscosity, cS = ");
    scanf("%g", &vist);
    printf("Enter Measuring Temperature, C = ");
    scanf("%g", &temp);
    printf("Enter Tolerance = ");
    scanf("%g", &btol);

    bguess=0.6;
    ao=log(vist)/log(10.0);
    tq=310.93/(temp+273.15);
    ak=ao+c;
    p=log(tq);
```

```

bnew = bguess;
bold = bnew;
if(abs(bold-bnew) > btol)
{
    printf("ak = %g\n",ak);
    q = log(ak);
    fb = log(bold) + ss*bold*p + is*p-q;
    fder = 1./bold + ss*p;
    bnew = bold-fb/fder;
}
printf("B = %g\n",bnew);
if(response == 'y')
{
    printf("Enter Temperature for Prediction, C = ");
    scanf("%g", &temp2);
    s = ss*b + is;
    sl = 310.93/(temp2 + 273.15);
    ssl = power(sl,s);
    lvis = b*ssl-c;
    vis = power(10.0,lvis);
    printf("Predicted Viscosity, cS = %g", vis);
    printf("Predict another Viscosity (y/n)?");
    scanf("%s", response);
}
}
/* finds base to the exp power */

```

```

double power(base,exp)

double base;

int exp;

{
    double answer;

    if ( exp > 0)

    {
        for (answer = 1.0; exp > 0; exp--)

            answer *= base;

        return(answer);

    }

    else if (base != 0)

    {
        for (answer = 1.0; exp < 0; exp++)

            answer /= base;

        return(answer);

    }

    else /* base = 0 and exp <= 0 */

    {
        printf("0 to the %d power is not allowed!\n", exp);

        return(0);

    }

}

```

Appendix D
Fluid Properties

Table D.1 : Viscosity and Density of 1% NaCl solution

Temperature (°C)	Density (kg/m ³)	Viscosity (mPa.s)
50.0	988.07	0.544
100.0	958.38	0.280
150.0	917.30	0.182

Table D.2 : Viscosity of Vitrea 150

Temperature (°C)	Viscosity (mPa.s)
15.0	
20.0	455.85
	448.25
	442.55
	439.39
40.0	136.76
	129.16
	123.46
	121.56
59.0	47.48
	46.85
	46.53
	47.10
	46.85
	47.21
75.0	26.21
	26.59
	26.84

Table D.3: Density of Vitrea 150

Temperature (°C)	Density (kg/m ³)
20.0	877.0
40.0	861.3
50.0	857.2
60.0	853.8
80.0	838.9
100.0	828.0
125.0	814.5

Appendix E
Raw Relative Permeability Data

Table E.1 :Two-Phase Brine/Oil Data at 75°C

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Brine saturation	Oil saturation	Core pressure drop (psi)
10.0	0.0	0.1	0.90	0.45
0.08	4.0	0.15	0.85	13.3
0.2	2.0	0.199	0.801	6.6
0.5	0.5	0.304	0.696	2.0
4.0	0.2	0.533	0.467	1.46
10.0	0.02	0.821	0.179	0.88
10.0	0.0	0.827	0.173	0.96

Table E.2 :Two-Phase Gas/Oil Data at 75°C

Gas flow rate (cc/min)	Oil flow rate (cc/min)	Gas saturation	Oil saturation	Core pressure drop (psi)
0.0	5.0	0.0	0.897	10.5
10.0	2.0	0.04	0.857	4.5
30.0	1.0	0.05	0.847	2.43
100.0	0.3	0.093	0.804	1.36
300.0	0.05	0.378	0.519	1.22
900.0	0.01	0.554	0.343	0.95
1000.0	0.0	0.677	0.22	1.15

Table E.3 : Two-Phase Brine/Oil Data at 125°C

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Brine saturation	Oil saturation	Core pressure drop (psi)
10.0	0.0	0.15	0.85	0.253
0.01	4.0	0.158	0.842	3.67
0.5	0.5	0.389	0.611	0.91
1.0	0.3	0.487	0.513	0.55
2.0	0.1	0.513	0.487	0.40
3.0	0.08	0.627	0.373	0.49
4.0	0.05	0.675	0.325	0.47
5.0	0.01	0.743	0.257	0.40
5.0	0.0	0.76	0.24	0.34

Table E.4 :Two-Phase Gas/Oil Data at 125°C

Gas flow rate (cc/min)	Oil flow rate (cc/min)	Gas saturation	Oil saturation	Core pressure drop (psi)
0.0	5.0	0.0	0.859	4.74
10.0	2.0	0.037	0.822	1.81
30.0	1.0	0.067	0.792	1.41
100.0	0.3	0.207	0.652	0.93
300.0	0.05	0.485	0.374	0.57
900.0	0.01	0.676	0.244	0.63
1000.0	0.0	0.699	0.221	0.55

Table E.5 :Three-Phase Data at 75°C (Run 1)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.45
0.05	4.0	0.0	0.164	0.83	0.0	13.8
0.05	4.0	50.0	0.156	0.688	0.156	22.2
0.10	3.0	100.0	0.17	0.658	0.172	18.4
0.20	2.0	200.0	0.20	0.633	0.167	12.3
0.40	1.0	400.0	0.205	0.563	0.232	8.2
0.60	0.5	600.0	0.22	0.522	0.258	5.1
1.0	0.1	750.0	0.275	0.377	0.348	2.2
1.0	0	750.0	0.325	0.11	0.565	1.25

Table E.6 :Three-Phase Data at 75°C (Run 2)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.452
0.05	4.0	0.0	0.081	0.919	0.0	13.1
0.05	4.0	20.0	0.17	0.741	0.089	18.6
0.1	3.0	30.0	0.18	0.696	0.124	16.2
0.25	2.0	50.0	0.205	0.665	0.13	11.1
0.50	1.0	75.0	0.21	0.608	0.182	6.96
1.0	0.5	100.0	0.26	0.561	0.179	4.45
3.0	0.05	300.0	0.44	0.288	0.272	1.65
5.0	0.0	500.0	0.50	0.119	0.382	1.54

Table E.7 :Three-Phase Data at 75°C (Run 3)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.47
0.25	4.0	0.0	0.241	0.759	0.0	14.7
0.25	4.0	20.0	0.20	0.633	0.167	22.7
0.75	2.0	40.0	0.23	0.59	0.18	11.9
1.0	1.0	50.0	0.26	0.544	0.196	7.07
2.5	0.25	70.0	0.36	0.427	0.213	3.04
3.0	0.15	80.0	0.40	0.374	0.226	2.43
5.0	0.05	100.0	0.46	0.241	0.279	1.66
5.0	0.0	100.0	0.52	0.105	0.375	1.33

Table E.8 : Three-Phase Data at 75°C (Run 4)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.43
0.1	4.0	0.0	0.179	0.821	0.0	14.9
0.1	4.0	20.0	0.17	0.691	0.139	20.2
0.3	3.0	60.0	0.18	0.624	0.196	19.4
0.5	2.0	100.0	0.205	0.614	0.181	13.0
1.0	1.0	140.0	0.24	0.55	0.21	8.2
2.0	0.5	180.0	0.275	0.49	0.235	5.4
4.0	0.1	220.0	0.37	0.325	0.305	2.63
5.0	0.0	250.0	0.50	0.103	0.397	1.6

Table E.9 : Three-Phase Data at 75°C (Run 5)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.57
5.0	0.05	0.0	0.677	0.323	0.0	0.79
5.0	0.05	20.0	0.683	0.276	0.041	1.19
5.0	0.0	20.0	0.691	0.131	0.178	0.91

Table E.10 :Three-Phase Data at 75°C (Run 6)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.601
1.0	0.05	0.0	0.425	0.558	0.0	0.73
1.0	0.05	20.0	0.37	0.513	0.117	0.96
1.0	0.0	20.0	0.45	0.288	0.262	0.74

Table E.11 :Three-Phase Data at 125°C (Run 1)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.25
0.05	4.0	0.0	0.263	0.737	0.0	4.28
0.05	4.0	50.0	0.24	0.685	0.075	4.60
0.2	2.0	200.0	0.25	0.587	0.163	3.37
0.6	0.5	600.0	0.29	0.41	0.30	2.29
1.0	0.1	750.0	0.32	0.252	0.428	2.0
1.0	0.0	750.0	0.37	0.06	0.57	1.88

Table E.12 :Three-Phase Data at 125°C (Run 2)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.281
0.05	4.0	0.0	0.111	0.889	0.0	4.22
0.05	4.0	20.0	0.22	0.769	0.011	4.02
0.1	3.0	30.0	0.24	0.731	0.029	3.93
0.25	2.0	50.0	0.26	0.684	0.056	2.96
0.5	1.0	75.0	0.265	0.612	0.123	1.93
1.0	0.5	100.0	0.31	0.532	0.158	1.67
3.0	0.05	300.0	0.46	0.237	0.303	1.32
5.0	0.0	500.0	0.50	0.135	0.365	1.47

Table E.13 :Three-Phase data at 125°C (Run 3)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.25
0.25	4.0	0.0	0.21	0.79	0.0	4.6
0.25	4.0	20.0	0.24	0.523	0.237	3.54
0.75	2.0	40.0	0.30	0.464	0.236	3.96
2.5	0.25	70.0	0.42	0.243	0.337	0.81
5.0	0.05	100.0	0.53	0.082	0.388	1.46
5.0	0.0	100.0	0.52	0.07	0.41	0.76

Table E.14 :Three-Phase Data at 125°C (Run 4)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.28
0.1	4.0	0.0	0.118	0.882	0.0	4.7
0.1	4.0	20.0	0.208	0.781	0.011	5.4
0.3	3.0	60.0	0.25	0.695	0.055	4.86
0.5	2.0	100.0	0.27	0.659	0.071	3.4
1.0	1.0	140.0	0.28	0.575	0.145	2.39
2.0	0.5	180.0	0.33	0.449	0.221	1.87
4.0	0.1	220.0	0.43	0.256	0.314	1.49
5.0	0.0	250.0	0.51	0.13	0.36	1.07

Table E.15 :Three-Phase Data at 125°C (Run 5)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.35
2.0	0.05	0.0	0.62	0.38	0.0	0.37
2.0	0.05	20.0	0.58	0.285	0.135	0.56
5.0	0.0	20.0	0.662	0.138	0.20	0.72

Table E.16 :Three-Phase Data at 125°C (Run 6)

Brine flow rate (cc/min)	Oil flow rate (cc/min)	Gas flow rate (scc/min)	Brine saturation	Oil saturation	Gas saturation	Core pressure drop (psi)
10.0	0.0	0.0	1.0	0.0	0.0	0.37
0.05	1.0	0.0	0.197	0.803	0.0	0.59
1.0	0.05	0.0	0.609	0.391	0.0	0.33
1.0	0.05	20.0	0.596	0.284	0.12	0.54
1.0	0.0	20.0	0.59	0.149	0.261	0.56

Appendix F
Calculated Relative Permeability Data

Table F.1 :End-Effect Evaluation Experiment

Original Core Holder			Modified Core Holder		
S_w (%)	k_{ro}	k_{rw}	S_w (%)	k_{ro}	k_{rw}
9.4	0.773	0.0	10.0	0.786	0.0
13.7	0.728	0.00003	15.0	0.821	0.000271
16.9	0.670	0.000184	19.9	0.827	0.00136
18.9	0.728	0.0006	30.4	0.683	0.0113
22.9	0.650	0.00214	53.3	0.374	0.123
28.2	0.557	0.00919	82.1	0.062	0.511
34.7	0.488	0.0268	82.7	0.0	0.469
47.0	0.308	0.1017			
59.5	0.184	0.243			
84.3	0.077	0.634			
84.5	0.0	0.634			

Table F.2 : Two-Phase Brine/Oil Relative Permeability at 75°C

S_w (%)	S_o (%)	k_{ro}	k_{rw}
10.0	90.0	0.786	0.0
15.0	85.0	0.821	0.000271
19.9	80.1	0.827	0.00136
30.4	69.6	0.683	0.0113
53.3	46.7	0.374	0.123
82.1	17.9	0.062	0.511
82.7	17.3	0.0	0.469

Table F3 :Two-Phase Gas/Oil Relative Permeability at 75°C

S_g (%)	S_o (%)	k_{ro}	k_{rg}
0.0	89.7	0.76	0.0
4.0	85.7	0.73	0.000019
5.0	84.7	0.68	0.000116
9.3	80.4	0.64	0.000195
37.8	51.9	0.12	0.11
55.4	34.3	0.031	0.36
67.7	22.0	0.0	0.61

Table F.4 : Two-Phase Brine/Oil Relative Permeability at 125°C

S_w (%)	S_o (%)	k_{ro}	k_{rw}
15.0	85.0	0.82	0.0
15.8	84.2	0.80	0.000527
38.9	61.1	0.77	0.0413
48.7	51.3	0.63	0.0912
51.3	48.7	0.51	0.105
62.7	37.3	0.308	0.22
67.5	32.5	0.264	0.272
74.3	25.7	0.24	0.385
82.0	18.0	0.0	0.527

Table F.5 :Two-Phase Gas/Oil Relative Permeability at 125°C

S_o (%)	S_o (%)	k_{ro}	k_{rg}
0.0	85.9	0.68	0.0
3.7	82.2	0.62	0.000074
6.7	79.2	0.535	0.00029
20.7	65.2	0.35	0.021
48.5	37.4	0.071	0.192
61.9	24.0	0.013	0.706
63.8	22.1	0.0	0.72

Table F.6 :Three-Phase Relative Permeability at 75°C (Run 1)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.794	0.00016	0.0	0.164	0.83	0.0
0.493	0.00010	0.00014	0.156	0.688	0.156
0.446	0.00024	0.00033	0.17	0.658	0.172
0.446	0.00073	0.00102	0.20	0.633	0.167
0.335	0.0022	0.0033	0.205	0.563	0.232
0.271	0.0053	0.0084	0.22	0.522	0.258
0.127	0.02	0.03	0.275	0.377	0.348
0.0	0.036	0.071	0.325	0.11	0.565

Table F.7 : Three-Phase Relative Permeability at 75°C (Run 2)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.837	0.00016	0.0	0.081	0.919	0.0
0.589	0.00012	0.000078	0.17	0.741	0.089
0.507	0.00028	0.00013	0.18	0.696	0.124
0.494	0.0010	0.00033	0.205	0.665	0.13
0.395	0.0032	0.00084	0.21	0.608	0.182
0.311	0.01011	0.0019	0.26	0.561	0.179
0.086	0.082	0.02	0.44	0.288	0.272
0.0	0.146	0.0375	0.50	0.119	0.381

Table F.8 :Three-Phase Relative Permeability at 75°C (Run 3)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.746	0.00077	0.0	0.241	0.759	0.0
0.482	0.00050	0.000063	0.20	0.633	0.167
0.461	0.00284	0.00025	0.23	0.59	0.18
0.389	0.00637	0.00056	0.26	0.544	0.196
0.229	0.037	0.0021	0.36	0.427	0.213
0.172	0.056	0.0032	0.40	0.374	0.226
0.085	0.136	0.0067	0.46	0.241	0.279
0.0	0.169	0.0096	0.52	0.105	0.375

Table F.9 :Three-Phase Relative Permeability at 75°C (Run 4)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.736	0.00030	0.0	0.179	0.821	0.0
0.542	0.00022	0.000063	0.17	0.691	0.139
0.423	0.0070	0.00019	0.18	0.624	0.196
0.422	0.0017	0.00048	0.205	0.614	0.181
0.335	0.0055	0.00114	0.24	0.55	0.21
0.255	0.0167	0.0023	0.275	0.49	0.235
0.106	0.068	0.0069	0.37	0.325	0.305
0.0	0.141	0.0156	0.50	0.103	0.397

Table F.10 :Three-Phase Relative Permeability at 75°C (Run 5)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.235	0.361	0.0	0.677	0.323	0.0
0.152	0.239	0.003	0.683	0.276	0.041
0.0	0.313	0.005	0.691	0.131	0.178

Table F.11 :Three-Phase Relative Permeability at 75°C (Run 6)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.273	0.082	0.0	0.442	0.558	0.0
0.20	0.063	0.005	0.37	0.513	0.117
0.0	0.081	0.011	0.45	0.288	0.262

Table F.12 :Three-Phase Relative Permeability at 125°C (Run 1)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.682	0.00029	0.0	0.263	0.737	0.0
0.634	0.00027	0.001	0.24	0.685	0.075
0.44	0.0015	0.0056	0.25	0.587	0.163
0.161	0.0066	0.0276	0.29	0.41	0.30
0.037	0.0125	0.042	0.32	0.252	0.428
0.0	0.0133	0.046	0.37	0.06	0.57

Table F.13 :Three-Phase Relative Permeability at 125°C (Run 2)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.77	0.00033	0.0	0.111	0.889	0.0
0.808	0.00035	0.00055	0.22	0.769	0.011
0.62	0.00071	0.00082	0.24	0.731	0.029
0.55	0.0024	0.0019	0.26	0.684	0.056
0.43	0.0073	0.0049	0.265	0.612	0.123
0.25	0.017	0.0080	0.31	0.532	0.158
0.032	0.064	0.035	0.46	0.237	0.303
0.0	0.095	0.05	0.50	0.135	0.365

Table F.14 :Three-Phase Relative Permeability at 125°C (Run 3)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.63	0.0014	0.0	0.21	0.79	0.0
0.45	0.0018	0.00058	0.24	0.523	0.237
0.37	0.0047	0.00097	0.30	0.464	0.236
0.24	0.077	0.0205	0.42	0.243	0.337
0.026	0.086	0.009	0.53	0.082	0.388
0.0	0.16	0.04	0.52	0.07	0.41

Table F.15 :Three-Phase Relative Permeability at 125°C (Run 4)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.69	0.0006	0.0	0.118	0.882	0.0
0.60	0.00052	0.00039	0.208	0.781	0.011
0.50	0.0017	0.0012	0.25	0.695	0.055
0.48	0.0041	0.0031	0.27	0.659	0.071
0.34	0.012	0.0068	0.28	0.575	0.145
0.22	0.03	0.012	0.33	0.449	0.221
0.06	0.075	0.021	0.43	0.256	0.314
0.0	0.131	0.043	0.51	0.13	0.36

Table F.16 :Three-Phase Relative Permeability at 125°C (Run 5)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
0.164	0.19	0.0	0.62	0.38	0.0
0.10	0.125	0.0024	0.58	0.285	0.135
0.0	0.243	0.013	0.662	0.138	0.20

Table F.17 :Three-Phase Relative Permeability at 125°C (Run 6)

k_{ro}	k_{rw}	k_{rg}	S_w	S_o	S_g
0.0	1.0	0.0	1.0	0.0	0.0
1.0	0.0031	0.0	0.197	0.803	0.0
0.20	0.112	0.0	0.609	0.391	0.0
0.111	0.069	0.0015	0.596	0.284	0.12
0.0	0.066	0.082	0.59	0.149	0.261

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